THE UNIVERSITY OF ALBERTA

NATURAL GAS EXPLORATION AND DEVELOPMENT IN ALBERTA

BY

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research for acceptance, a thesis entitled .... NATURAL GAS EXPLORATION AND DEVELOPMENT IN ALBERTA .... submitted by .... Gordon J. Moynham .... in partial fulfilment of the requirements for the degree of Master of .... Arts ....

ABSTRACT

The Alberta natural gas industry is increasing in importance as energy demands in Canada and the U.S. continue to grow and existing supplies are depleted. This thesis examines the natural gas industry and develops the proposition that natural gas is not a mere byproduct of the search for oil but, rather, is a desired commodity that is explored for and developed separately from oil and other energy sources.

An overview of the technological and economic conditions in the industry is presented. Government regulation of the industry is examined and models of field development patterns are presented. Costs to develop certain fields within the Province of Alberta are estimated and the work done is related to further useful research possibilities.

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TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

LIST OF TABLES

LIST OF ILLUSTRATIONS

Figure | Page

INTRODUCTION

Sales of Canadian natural gas in 1970 were approximately one and one-half trillion cubic feet providing gross revenues of $1.9 billion.[1] Of total Canadian production, the Province of Alberta has, since 1962, consistently accounted for slightly more than 80 per cent.[2] Exports to the United States have, in the past 10 years, increased dramatically with every indication of increasing still further during the 1970's as that country's energy requirements continue to grow and energy supplies dwindle. Consequently, natural gas will continue to gain in importance during the coming decade. The value of remaining marketable reserves at December 31, 1969 - in terms of the current wellhead price only - was approximately $9 Billion.[3] With only about 60 per cent of the province's ultimate marketable reserves discovered to date and an increasing value for gas in the future, the value of this resource to the Province of Alberta merits considerable attention.

This thesis develops the proposition that natural gas is no longer a mere byproduct of oil search but, rather, is explored for and developed in its own right. It is both economically separate and analytically separable from oil and other energy resources.

Chapter I explains what natural gas is, how it is produced and marketed in Canada and the geological aspects of natural gas. Gas is found to occur in fairly definite geological patterns (as is oil and natural gas liquids). The ways in which natural gas is regulated are also explored with implications

for field producers (particularly price implications) drawn.

Chapter II discusses problems of analysing costs in the natural gas industry. Gas in association with oil presents some difficulties in cost allocations which are dealt with within a theoretical framework. The major point of the chapter is that costs can be apportioned to the natural gas industry in an economically meaningful way.

The problem of cost allocation to gas has been particularly important - and difficult - in the United States where the field price of natural gas is subject to regulation by the Federal Power Commission. The problem of keeping consumer prices as low as possible without discouraging new exploration for gas has been a difficult one to handle. That the need for more research in this area exists has been clearly stated by Resources for the Future, Inc. as follows:

> The first field of research that suggests itself is that of the methods of cost estimation used for establishing field prices. The effort to base field prices on average costs ... leads into troublesome technical problems of estimation. We shall not attempt to describe the difficulties. To a considerable degree they arise out of the intimate association of oil and gas costs. The problem is not simply one of dissociating gas costs from a well-established joint total; it carries back into the extremely limited state of knowledge concerning the costs of finding, developing, and producing petroleum properties.[4]

Other points developed in the second chapter are the problems of economic cost and replacement cost, joint costs and data availability in the Province of Alberta.

Chapter III discusses the regulation of the Alberta natural gas industry by the National Energy Board and the

Alberta Oil and Gas Conservation Board. Liberalization of regulations by these bodies in the past 2 years has provided a tremendous stimulus to exploration in Alberta recently. This has occurred at a time when the problem facing the industry is one of locating reserves with which to supply future demands rather than procuring markets. Policies of the Alberta Department of Mines and Minerals are briefly examined insofar as they also help to stimulate oil and gas exploration and development in Alberta.

In Chapter IV an effort is made to explain patterns of field development in gas fields of the Province. Both a constrained and an unconstrained model of field development are presented and the predictions of these models itemized and compared to actual patterns of development in gas-only fields in Alberta. The chapter concludes with cost estimates for developing certain selected fields in the Province of Alberta.

In the Conclusion, various possibilities for further research are outlined. The possible utilization of this thesis as a basis for further illuminating research in the gas industry may be the most useful outcome of the work done.

FOOTNOTES

[1]Oilweek, January 19, 1970, p. 35.

[2]Financial Post, Survey of Oils (Toronto: McLean-Hunter Limited), 1962-1970.

[3]Reserve estimates from the Oil and Gas Conservation Board of Alberta, Reserves of Crude Oil, Gas, ...,: December 31, 1969 (Calgary, Alberta: 1970).

[4]Resources for the Future, Inc. U.S. Energy Policies: An Agenda for Research (Baltimore: The John Hopkins Press, 1969), p. 59. Italicized in the original.

CHAPTER I

TECHNICAL AND GEOLOGICAL ASPECTS OF NATURAL GAS

The Nature and Composition of Natural Gas

Natural gas is a simple hydrocarbon of the paraffin series, the molecules of which are composed of atoms of hydrogen and carbon. It is gaseous when surfaced and "dry gas"[1] consists of 85 to 95 per cent methane (although there is considerable variation in the composition of gas - both "wet" and "dry" as found in the reservoir[2]).

Table 1 indicates the components of raw natural gas. In the paraffin series, the least complex forms, or short chain compounds, are gases, the medium chain lengths are liquids and the most complex forms (not included in Table 1) are inert solids. The inertness of the paraffin series makes natural gas non-toxic to human beings (unlike the very poisonous manufactured gases) and this property combined with the high energy content[3] and the cleanliness of natural gas makes it a preferred fuel.

Natural gas (and other hydrocarbons) occur in geological "traps" or reservoirs 1,000 to 16,000 feet below the surface. All traps possess an impervious "cap rock" which acts as a sealer to trap any accumulation of gas or oil that has migrated into the structure. The rock in the reservoir itself must be porous (void spaces in the rock) and there must be interconnections between the void spaces or permeability of the trap. Permeability allows the gas (or oil) to flow

TABLE 1

CONSTITUENTS OF RAW NATURAL GAS

Raw Natural Gas Mixture	Chemical Symbol	Paraffin Series Chemical Formula	Product Groupings	Paraffin Series Natural State
Methane	C_1	CH_4	Sales gas	natural gas, difficult to liquify
Ethane	C_2	C_2H_6	" "	
Propane	C_3	C_3H_8	Propane	gas, easily liquified (LPG)
Butane	C_4	C_4H_{10}	Butane	
Pentanes	C_5	C_5H_{12}	Gasoline	liquid, very volatile
Hexanes plus	C_6+	$C_6H_{14}+$	Condensate	liquid
Carbon dioxide	CO_2	–[a]	Waste	–[a]
Nitrogen	N_2	–[a]	"	–[a]
Water vapour	H_2O	–[a]	"	–[a]
Mercaptans	RSH	–[a]	"	–[a]
Hydrogen sulphide	H_2S	–[a]	Sulphur	–[a]

Source: Canadian Gas Association, Paper No. 1 and Paper No. 48 of the Technical Education Committee of the Canadian Gas Association, What's Your Gas Q?

[a]Not a component of the paraffin series. The general formula for members of the paraffin series is C_NH_{N+2}.

through the void spaces in the rock and up the hole drilled through the "cap rock".[4] The more porous and permeable the rock in the reservoir, the more oil, gas and water there will be and the greater will be the amount of oil in place in the trap.[5] More will be said about these traps in the next section of this chapter. At this point it need only be stressed that any combination of gas, oil or water may be found in a trap. Natural gas may be found alone (non-associated gas) or it may be found with oil (casinghead gas) either dissolved in the oil (dissolved natural gas) or in a layer above the oil (associated gas). Associated gas always occurs above the oil and oil always occurs above water owing to relative differences of their specific gravity. Figure 1 diagrammatically presents the various conditions under which natural gas is found.

Recovery of natural gas from a reservoir is made possible by the pressure differential between the sealed trap and the surface pipeline. As long as the pressures in the trap are greater (either because of the gas itself expanding or the force of underground water) the gas will move to the surface. The production, processing, transmission and sale of natural gas are discussed in the third section of this chapter.

When a number of traps occur close together (either side by side or one above the other) they form a "field" and, when a number of different fields in a large area (such as Western Canada) have reasonably similar geological ages, depths

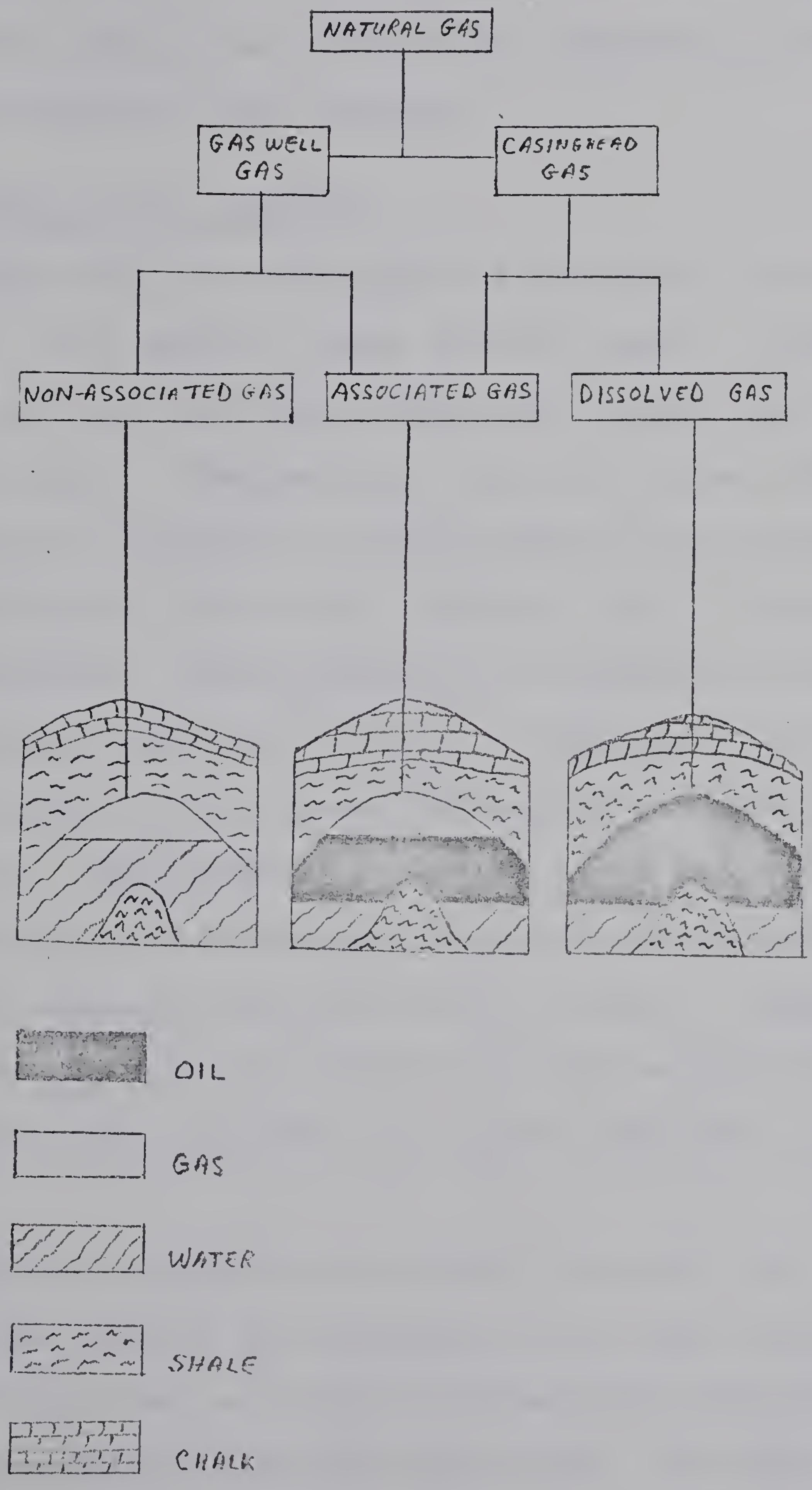

Fig. 1 Classification of natural gas occurrence (Clark A. Hawkins, The Field Price Regulation of Natural Gas (Tallahassee: Florida State University Press, 1969), p.3.

and pressures, they form a "basin".[6]

Geological configurations provide valuable clues as to the presence of subsurface hydrocarbon reservoirs. This geological information is necessary for an understanding of the exploration for gas and oil and is, therefore, presented in the next section of this chapter.

Geology of Natural Gas Location

Comprising the outer zone of the earth - the "crust" of the earth - are rocks of three general types. "Igneous" rocks (made by fire) are those which have cooled from a molten state (e.g., lava). "Sedimentary" rocks are those which have been formed by the wasting or wearing down of the earth's crust by mechanical (rain, snow, glaciers, etc.) and/or chemical processes. Three quarters of the land area of the earth is directly underlain by rocks of this type and it is these rocks which are the source of natural gas (and petroleum) accumulations. "Metamorphic" rocks are rocks which were formerly igneous or sedimentary and have been changed by temperature and pressure within the earth's crust.[7] These layers of rock formations have accumulated through geological time and geologists have classified the layers according to their age.

Table 2 presents the reserves of crude oil, natural gas liquids and natural gas according to the era, period and/or epoch in which they are found (epochs being the shortest unit of the geological calendar identified). The Mesozoic era - particularly the Cretaceous periods - and the Paleozoic

TABLE 2

RESERVES OF CRUDE OIL, NATURAL GAS LIQUIDS AND NATURAL GAS IN ALBERTA BY GEOLOGICAL AGE
DECEMBER 31, 1969
(in per cent)

Era[a]	Period	Epoch	Probable Ultimate Reserves: Crude Oil	Natural Gas Liquids	Natural Gas
Cenozoic					
	Quaternary		-	-	-
	Tertiary		-	-	-
Mesozoic					
	Upper Cretaceous				
		Cardium	18.6	6.0	3.4
		Other U.C.	.6	.1	3.4
	Lower Cretaceous				
		Viking	2.1	.7	6.8
		Mannville	1.9	2.4	7.8
		Other L.C.	2.5	.5	7.8
	Jurassic		---	.2	.9
	Triassic		.1	---	.2
Paleozoic					
	Carboniferous				
		Permian and Pennsylvanian	---	-	.1

--continued--

TABLE 2 (continued)

		Mississippian: Turner Valley-Ratcliffe	2.7	27.0	24.0
		Pekisko-Frobisher-Alida	.3	1.5	2.8
		Other Mississippian	.1	1.8	5.4
	Devonian				
		Wabamun (Crossfield)	.1	2.3	11.4
		Nisku-Birdbear	12.4	.3	.6
		Leduc	24.0	23.5	14.4
		Beaverhill Lake	17.1	29.3	8.5
		Gilwood	5.5	.9	.5
		Keg River-Winnipegosis	11.3	3.0	1.2
		Other Devonian	.7	.5	.8
	Silurian		-	-	-
	Ordovician		-	-	-
	Cambrian		-	-	-
Pre-Cambrian			-	-	-
			100.0	100.0	100.0

Source: Percentages calculated from Canadian Petroleum Association, Statistical Yearbook, 1969 (Calgary, Alberta: 1970), pp. 59, 63, 71. Geological classification from Eric J. Hanson, Dynamic Decade (Toronto: McClelland & Stewart Ltd., 1958), p. 28.

[a]Listed from youngest to oldest formations.

--- amount negligible

- nil

era - particularly the Devonian period and the Mississippian epoch - account for all of Alberta's reserves (and production) to date. Although rocks of the tertiary period have provided approximately one-half of the world's oil, the tertiary formations are missing in most of Alberta and have therefore been unimportant in this province.[8]

While all of the formations mentioned will yield oil and/or gas and/or gas liquids, it should be noted that certain formations are relatively more important in producing one or another of these products. The Upper Cretaceous period is quite important for oil (approximately 20 per cent of probable ultimate reserves) while not so important for natural gas and natural gas liquids (between 6 and 7 per cent of total reserves for each of these products). Lower Cretaceous formations contain almost one quarter of the probable ultimate natural gas reserves but are relatively unimportant for natural gas liquids (less than 4 per cent) and oil (6.5 per cent). The Jurassic and Triassic periods of the Mesozoic era are virtually barren of all three products.

Proceeding to the Paleozoic era, the Permian and Pennsylvanian epochs in the Carboniferous period contain only traces of natural gas and oil. However, the Mississippian epoch in the Carboniferous period is of great importance for natural gas (roughly one third of probable ultimate reserves) and natural gas liquids (slightly more than 30 per cent) but of little importance for oil (only 4.1 per cent of reserves). The Devonian period, on the other hand, is of tremendous

importance for all three products - but most important for oil. Nearly three quarters of the oil reserves are located in the Devonian formations. Also, 60 per cent of the natural gas liquid reserves are located in these formations but "only" 37.4 per cent of the gas reserves of the province. However when one examines individual epochs within the Devonian period it becomes evident that natural gas is far more important in the Wabamun formation (where only a trace of oil exists) while oil is important in the Nisku-Birdbear formation (where only a small amount of gas exists). The Leduc and Beaverhill Lake formations are rich in oil, natural gas liquids and natural gas. The older Gilwood and Keg River formations contain approximately one sixth of the total oil reserves of the province but very little natural gas (1.7 per cent).

This somewhat lengthy elaboration of the results contained in Table 2 is an attempt to illustrate the fairly predictable relationship between the various formations and the type of hydrocarbon that a driller may expect to find. As a simple example, assume that all of the Mesozoic and Paleozoic formations are represented in a drilling area. An individual wildcatter, if looking only for oil (a common situation 3 or 4 decades ago when gas was an almost useless byproduct of the search for oil) might rationally be expected to cease drilling if no oil were located in the Upper Cretaceous rocks and funds were too limited to go deeper into the Devonian formations. To drill into Lower Cretaceous rocks would run the "risk" of finding gas with less chance of oil

being found. A more contemporary example is the expectation (ceteris paribus) that a wildcatter will not cease before drilling through the Lower Cretaceous rocks (since gas is no longer a "useless byproduct").

Further information concerning productive formations in Alberta is contained in Table 3 which lists the 66 "major" natural gas fields in Alberta at the end of 1969. Table 4 reclassifies the largest (in terms of initial gas in place) fields of Alberta according to geological age and type of gas (associated, non-associated and/or solution). The results of this analysis are quite revealing. Non-associated gas forms about 70 per cent of the original reserves in the province. However, the percentage of non-associated gas in the largest 45 fields varies between the various types of productive formations. The huge solution gas reserves at Pembina result in the Upper Cretaceous formations showing only 42.6 per cent of the gas in those formations being non-associated. However, the Lower Cretaceous formations are average in the distribution of gas types. Moving into the Upper Mississippian formations there is a tendency toward associated rather than dissolved gas. The Lower Mississippian and Upper Devonian (Wabamum) reserves are, however, almost entirely non-associated but the situation changes in the Lower Devonian (Beaverhill Lake and Leduc) formations. Beaverhill Lake formation reserves are split approximately 60-40 between non-associated and solution reserves (with virtually no associated gas). The Leduc formation reserves contain even less non-associated

TABLE 3

MAJOR NATURAL GAS FIELDS IN ALBERTA,
PRODUCING ZONES AND RESERVES,
DECEMBER 31, 1969
(in Bcf)

Name of Field	Main[a] Producing Zone(s)	Initial Gas In Place[b]				Initial Marketable Gas	Marketable Gas Remaining, December 31, 1969
		Non-Associated	Associated	Solution	Total		
Fields with more than 1 trillion cubic feet of initial gas in place							
1. Crossfield	Mississippian (Rundle) and Upper Devonian (Wabamun)	6,130	-	74	6,204	3,413	2,087
2. Kaybob (and Kaybob South)	Lower Cretaceous and Devonian (Beaverhill Lake)	4,936	92	538	5,566	2,991	2,851
3. Pembina	Upper Cretaceous (Cardium Solution)	463	21	4,190	4,674	1,258	1,050
4. Waterton[c]	Mississippian (Rundle) and Wabamun	4,049	-	-	4,049	2,137	1,894
5. Turner Valley	Mississippian (Rundle)	-	1,570	1,400	2,970	860	174
6. Edson	Mississippian (Elkton)	2,601	-	-	2,601	2,090	1,846
7. Medicine Hat[c]	Upper Cretaceous	2,571	-	-	2,571	2,014	1,382
8. Jumping Pound[c]	Mississippian	2,280	-	-	2,280	1,520	1,208
9. Westerose	Devonian	1,870	130	150	2,150	1,537	1,088

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TABLE 3 (continued)

10.	Harmattan-Elkton	Mississippian (Rundle)	480	1,178	180	1,838	1,106	1,091
11.	Pincher Creek[c]	Mississippian (Rundle)	1,800	-	-	1,800	540	282
12.	Strachan[c]	Devonian	1,770	-	-	1,770	1,200	1,200
13.	Swan Hills	Devonian (Beaver-hill Lake)	2	-	1,590	1,592	481	436
14.	Cessford	Lower Cretaceous	616	911	32	1,559	1,219	687
15.	Homeglen-Rimbey	Devonian	-	1,170	86	1,256	797	499
16.	Marten Hills[c]	Upper Devonian	1,255	-	-	1,255	892	888
17.	Harmattan East	Mississippian (Rundle)	-	1,060	190	1,250	892	892
18.	Carstairs	Mississippian (Elkton)	1,156	6	-	1,162	886	609
19.	Provost	Lower Cretaceous	1,117	20	5	1,142	965	669
20.	Nevis	Devonian (small amount of Lower Cretaceous)	1,106	-	-	1,106	850	631
21.	Rainbow	Devonian (Keg River)	164	148	773	1,085	642	642
22.	Viking-Kinsella[c]	Lower Cretaceous	1,058	-	-	1,058	831	387
23.	Brazeau River	Mississippian (Elkton)	1,050	-	-	1,050	744	727
24.	Wildcat Hills[c]	Mississippian (Rundle)	1,050	-	-	1,050	700	538

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TABLE 3 (continued)

25.	Gilby	Lower Cretaceous and Mississippian (Rundle)	1,009	26	-	1,035	806	622
	Fields with 500 to 999 Bcf. of initial gas in place							
26.	Bonnie Glen	Devonian (Leduc)	23	430	546	999	609	539
27.	Pine Creek[c]	Devonian (Leduc and Wabamun)	990	-	-	990	346	146
28.	Windfall	Devonian (Leduc)	25	710	230	965	528	449
29.	Leduc-Woodbend	Devonian (Leduc and Other)	76	524	320	920	605	448
30.	Judy Creek	Devonian (Beaver-hill Lake)	67	-	830	897	324	275
31.	Ferrier	Upper Cretaceous	28	520	331	879	587	583
32.	Alderson	Upper Cretaceous	828	-	-	828	510	487
33.	Carson Creek	Devonian (Beaver-hill Lake)	320	33	470	823	402	389
34.	Minnehik-Buck Lake	Mississippian (Pekisko)	817	-	-	817	608	483
35.	Ricinus	Devonian and Cardium (Assoc)	560	200	-	760	400	400
36.	Quirk Creek[c]	Mississippian (Rundle)	740	-	-	740	500	500
37.	Sylvan Lake	Lower Cretaceous and some Jurassic, Mississippian and Devonian	540	77	49	666	479	402

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TABLE 3 (continued)

38.	Lookout Butte[c]	Mississippian (Rundle)	660	-	-	660	450	367
39.	Beaverhill Lake-Fort Saskatchewan[c]	Lower Cretaceous (Viking)	651	-	-	651	523	372
40.	Gold Creek[c]	Devonian (Wabamun)	638	-	-	638	388	388
41.	Hussar	Lower Cretaceous	479	123	20	622	485	307
42.	Willesden Green	Lower Cretaceous	89	31	460	580	163	155
43.	Zama	Devonian (various)	350	24	179	553	362	362
44.	Lone Pine Creek	Devonian (Wabamun and Leduc)	402	129	10	541	358	337
45.	Berland River[c]	Devonian (Leduc and Wabamun)	500	-	-	500	341	341
	Fields with 250 to 499 Bcf. of initial gas in place							
46.	Wayne-Rosedale	Lower Cretaceous	488	6	-	494	390	307
47.	Bigstone[c]	Devonian (primarily Leduc)	478	-	-	478	320	308
48.	Wimborne	Devonian (Leduc)	5	362	110	477	202	148
49.	Mitsue	Devonian (Gilwood)	2	3	470	475	183	183
50.	Okotoks[c]	Devonian (Crossfield)	470	-	-	470	170	116
51.	Bindloss[c]	Lower Cretaceous (Viking and Mannville)	467	-	-	467	351	222
52.	Olds	Devonian (Wabamun)	34	350	62	446	266	214

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TABLE 3 (continued)

53.	Sturgeon Lake	Devonian (Leduc)	68	13	292	373	148	130
54.	Burnt Timber[c]	Mississippian (Rundle)	370	-	-	370	250	250
55.	Pine North-West[c]	Devonian (Leduc)	358	-	-	358	176	160
56.	Ghost Pine	Lower Cretaceous	315	38	-	353	248	204
57.	Simonette	Devonian (Leduc and Wabamun)	70	-	270	340	133	130
58.	Countess	Lower Cretaceous	317	20	-	337	271	177
59.	Westlock[c]	Lower Cretaceous	332	-	-	332	259	183
60.	Pouce Coupe[c]	Lower Cretaceous	315	-	-	315	221	63
61.	Craigend	Devonian and Lower Cretaceous	306	1	-	307	176	174
62.	Pendant D'Oreille[c]	Lower Cretaceous	305	-	-	305	249	123
63.	Redwater	Devonian (Leduc)	31	-	240	271	72	54
64.	Virginia Hills	Devonian (Beaver-hill Lake)	13	35	220	268	93	86
65.	Wizard Lake	Devonian (Leduc)	24	1	230	255	128	91
66.	Nipisi	Devonian (Gilwood)	-	-	250	250	100	100
	Total major fields		55,094	9,962	14,787	76,853		
	Other fields (less than 250 Bcf.) and confidential pools		12,493	1,320	1,210	15,013		
	Total reserves		64,587	11,282	15,997	91,866		
	Total reserves as a percentage		70.3	12.3	17.4	100.0		

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TABLE 3 (continued)

Sources: Oil and Gas Conservation Board, Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur, Province of Alberta: December 31, 1969 (Calgary, Alberta: 1970), pp. II-1 to II-65, and Oil and Gas Industry, 1958 (Calgary, Alberta: 1959), pp. 11, 13-17. E. J. Hanson, Dynamic Decade (Toronto: McClelland and Stewart Ltd., 1958), Chapter 19, esp. pp. 232-35.

[a]Contains at least 80 per cent (and usually 90 to 100 per cent) of the initial gas in place. In cases of two or more formations being listed, the ranking is in descending order of importance. It should also be noted that the designation of a field as (say) "Devonian" does not preclude the possibility of small amounts of gas in, perhaps, several other formations.

[b]All terms are defined in the Glossary.

[c]Is a gas field only - no oil reserves present at December 31, 1969.

TABLE 4

ANALYSIS OF RESERVES IN MAJOR[a] FIELDS OF ALBERTA

Age	Non-Associated Gas		Associated Gas		Solution Gas		Total	
	Amount (in Bcf)	Per Cent of Class	Amount (in Bcf)	Per Cent of Class	Amount (in Bcf)	Per Cent of Class	Amount (in Bcf)	Per Cent of Class
Upper Cretaceous	3,902	42.6	741	8.1	4,521	49.3	9,164	100.0
Lower Cretaceous	5,731	71.0	1,237	15.3	1,104	13.7	8,072	100.0
Mississippian								
- Rundle[b]	13,255	70.1	3,808	20.1	1,844	9.8	18,907	100.0
- Elkton	4,807	99.9	6	.1	-	-	4,813	100.0
- Other	3,097	100.0	-	-	-	-	3,097	100.0
Devonian								
- Wabamun	4,654	99.9	4	.1	-	-	4,658	100.0
- Beaverhill Lake	4,809	60.6	70	.9	3,061	38.5	7,940	100.0
- Leduc and Other	7,081	56.8	3,267	26.2	2,123	17.0	12,471	100.0
Total	47,336	68.5	9,133	13.2	12,653	18.3	69,122	100.0

Source: Derived from the information presented in Table 3. In cases where more than one "Main Producing Zone" is listed in Table 3, the reserves have been allocated to the various formations.

[a]Only the first 45 fields in Table 3 (that is, over 250 Bcf. Initial Gas in Place) are contained herein.

[b]Terms are not comparable to those used by the Canadian Petroleum Association in Table 2.

reserves (on a percentage basis) but considerably more than average associated reserves and about normal quantities of solution gas.

In summary then, it is found that non-associated reserves are predominant in Lower Mississippian and Upper Devonian formations, associated reserves are greater than average in Upper Mississippian and Leduc formations and solution gas reserves are concentrated in the Upper Cretaceous (Pembina field) and Beaverhill Lake formations. The key questions then are to what extent firms are able to direct their efforts toward the formations in which the desired product is more frequently found and, from a cost minimization standpoint, how depths are related to productive formations. Deeper wells involve rising costs per foot. If deeper wells typically yield lighter oil and a higher gas:oil ratio (as has been suggested[9]) then higher prices for natural gas (or, of course, gasoline and other products refined from lighter crudes) should induce the additional expenditures required to go deeper into the earth. These questions of marginal costs and joint cost separation are dealt with in Chapter 2. For the time being, it need only be pointed out that very definite patterns emerge when the various formations and reserves are examined - and the patterns are significant enough to justify further inquiry. In general - and only in general - only dry natural gas is likely to be found down to one or two thousand feet. It requires about three to four thousand feet of "over-burden" for oil to be present. Depending on the geothermal

gradiant, as one goes deeper lighter oils and gas condensates (wet gas together with greater quantities of hydrogen sulphide) are more prevalent. In other words shallower formations are more likely to contain dry gas or heavy crude.

It is important to realize that the various strata are sloped upwards from the Rocky Mountains toward the East. Therefore any particular formation will occur at widely varying depths (for example, non-associated gas in Carboniferous formations is found at depths ranging from 12,200 feet in Pincher Creek and Lookout Butte up to 7,425 feet in Crossfield and 4,475 feet at Eaglesham).[10] In looking at regional variations of the composition of natural gas (and crude oil) the two key factors to be considered are the circumstances surrounding the <u>deposition</u> of the sediments and subsequent <u>maturation</u> effects (that is, irreversible temperature - dependent reactions).[11]

Essentially, there is a wide range of probabilities associated with each formation in each area of the province as to what - if anything - is likely to be present. These varying probabilities underlie many of the decisions made during the process of deciding to drill a well and deciding, also, when to abandon exploration.

In laying the foundation for the discussion of the decision-making process of exploration firms, it is worthwhile spending time to discuss the overall production and marketing of natural gas in the industry and the effects of the industry's structure and regulatory constraints on exploration

and development in the field. This is done in the next section of this chapter.

Production and Marketing of Natural Gas in Canada

Stages of development and production in the oil and gas industry are usually described as follows:[12]

A) Exploration - A geologist and geophysicist will study an area to indicate favourable possibilities which can only be confirmed by drilling. In favourable areas (such as Alberta) a seismic survey party is used[13] but in the North it is customary to use gravity meter survey parties since the cost per mile is much less than that of a seismic survey party.

B) Drilling - The purpose of drilling is to provide a hole in which to place tubing to make a connection between the reservoir and the surface and, of course, this work can be fruitless and/or dangerous.

C) Production - Production can be subdivided into the following functions:

(i) lifting;

(ii) separating the oil from the gas and measuring the rate of production of both;

(iii) separating the water from the oil and gas;

(iv) burning off the gas or pipelining it to a gas processing plant.

After being brought to the surface the raw gas must

be processed to remove impurities - the amount of impurities varying greatly from one reservoir to another. Gas transmission companies insist on minimum quality standards in the gas received from producers, both for safety reasons (unreliable combustion conditions exist when impurities are present in the gas) and because transmission lines operate at pressures high enough to cause propanes and butanes (and the higher hydrocarbons) to condense out into the liquid phase in the pipelines, thus increasing the maintenance costs. Table 5 presents the analysis of gas transported from Alberta by Trans-Canada Pipe Lines Limited.

Gas processing plants are located at or near the fields and have increased from 9 in 1956 to 132 at the end of 1969 in Canada with 115 of them located in Alberta.[14] With 123 producing fields in Alberta at December 31, 1969[15] there is roughly one processing plant for each field. Nine firms account for approximately 75 per cent of the processing capacity in the province as shown in Table 6.

From the individual producer's point of view, gas processing is a concentrated or oligopsonistic stage of the industry. Hence, while individual producers must produce gas where they find it, processors and pipeline companies are able to put in facilities on an "if, as and when needed" basis (with drastically better information available). Individual processors are constrained by the ability of transmission companies to bypass fields if the prices are not competitive (taking into account their varying distances from the major

TABLE 5

ANALYSIS OF NATURAL GAS TRANSPORTED
BY TRANS-CANADA PIPE LINES LIMITED

Constituent	Volume Percent
Methane (CH_4)	91.50
Ethane (C_2H_6)	3.75
Propane (C_3H_8)	1.41
Butane (C_4H_{10})	0.58
Pentane (C_5H_{12})	0.15
Hexanes plus (C_6H_{14}+)	NIL
Nitrogen (N_2)	2.56
Oxygen (O_2)	NIL
Hydrogen (H_2)	NIL
Hydrogen Sulphide (H_2S)	NIL
	100.00%
BTU content per cubic foot (at 30 inches of mercury and 60^{o} Fahrenheit, wet)	1032
Specific gravity (Air = 1.0)	0.608

Source: Canadian Petroleum Association, "Chemical Characteristics of Natural Gas", _What's Your Gas Q?_ Paper No. 1 of the Technical Education Committee of the Canadian Gas Association (undated).

TABLE 6

CONCENTRATION OF OWNERSHIP IN GAS PROCESSING PLANTS IN ALBERTA
December 31, 1969

Company	Number of Plants	Raw Gas Capacity (MMcf. per day)	
		Total	Percentage
Pacific Petroleums (affiliate of Westcoast Transmission Co. Ltd.)	1	1,500	21.0
Gulf Oil Ltd.	7	917	12.8
Hudson's Bay Oil and Gas	8	738	10.3
Amoco Canada	7	555	7.7
Shell Oil	4	540	7.5
Home Oil	3	322	4.5
Canadian Superior	2	288	4.0
Jefferson Lake Petrochemicals Ltd.	2	286	4.0
Imperial Oil	6	199	2.8
Others (37)	75	1,817	25.4
TOTAL	115	7,162	100.0

Source: Financial Post, Survey of Oils, 1970 (Toronto: McLean-Hunter Limited, 1970), pp. 28-9.

Canadian Petroleum Association, Statistical Yearbook, 1969, (Calgary: 1970), pp. 137-42.

pipelines).

After being processed, the gas is gathered in lateral and trunk pipelines for distribution to consumers. About 25 per cent of natural gas deliveries in the province are for consumption in Alberta and are carried by 6 companies (two major ones) engaged in supplying gas to Alberta cities and municipalities and to large industrial plants (on contract). The remaining 75 per cent of gas deliveries in the Province of Alberta are carried by The Alberta Gas Trunk Line Company Limited for delivery to Trans-Canada Pipe Lines Limited (serving Canadian markets east of Alberta) and to Alberta and Southern Gas Co. Ltd. (which supplies the Canadian-Montana Pipe Line Company at the U.S. border and the El Paso Natural Gas Co. via Southwestern British Columbia under contract to Westcoast Transmission Co. Ltd.). Alberta Gas Trunk Line Company Limited and the local utility companies within the province are regulated and limited to a fixed rate of return on the rate base (8 1/4 per cent in the case of Alberta Gas Trunk) by the Public Utilities Board of Alberta. Furthermore, all exports from Canada must be approved by the National Energy Board and all exports from Alberta - either to the United States or other Canadian provinces - must be approved by the Oil and Gas Conservation Board of Alberta.[16] Government regulation of the industry is discussed more fully in Chapter III.

The three major trunk line companies in Canada (other than Alberta Gas Trunk) - Trans-Canada Pipe Lines

Limited, Alberta and Southern Gas Co. Ltd. and Westcoast Transmission Co. Ltd.[17] - are regulated as to tariffs and pipeline construction by the National Energy Board of Canada. Trans-Canada and Westcoast Transmission service local utilities in the other Canadian provinces which are, in turn, monopolies in their own areas but regulated (or owned outright by governments) as to rates of return and the type of service they must provide.

It is important to recognize that in the processing, transmission and distribution stages of the industry there are significant economies of scale plus monopsonistic and monopolistic features which are, in turn, checked by regulation. Economies of scale are particularly significant in transportation of the gas since a doubling of pipeline size will roughly double construction costs but will quadruple the volume of gas that can be transported. MacAvoy, using U.S. data for the early 1960's and a 10 per cent (before tax) interest rate on capital, estimated the costs for a 36-inch line to be about 40 per cent lower than for a 16-inch line. For smaller lateral lines used to gather gas from the field, the results are even more dramatic - over 60 per cent saving (per Mcf.) by using a 12-inch rather than a 6-inch line.[18]

<u>Implications of Industry Structure for Field Producers</u>

Pipeline company demands for field processed gas are derived from consumer demands which are, in turn, a function of: (1) the number of consumers in an area; (2) the type of users in an area (residential, commercial or industrial);

(3) characteristics (such as cleanliness) and prices of substitutes; (4) climatic conditions in areas served. The elasticity of demand by pipeline companies for natural gas is, therefore, affected by these factors, but is also a function of the distance from the market, transportation costs and quality (in terms of BTU's per cubic foot) of the gas. The pipeline companies contract with producers in the field to have gas delivered (subject to approval by the Oil and Gas Conservation Board of Alberta) over long periods (generally 25 years). In setting the final price for the gas there is some room for bargaining and the oligopsony power of the large transmission companies is important at this point. Special factors such as price renegotiation clauses or price escalator clauses (often one cent per Mcf. every five years) tend to decrease the initial price for the gas (since future adverse inflationary effects are offset by the special clauses) as well as decreasing total remuneration over the lifetime of the contract (owing to the reduction of risk to the producer).

Another special factor is that pipeline companies prefer a steady throughput of gas and also prefer large quantities that will enable them to reap the economies of scale associated with larger diameter lines. However, diminishing returns in production arise when the required uniform rate of production is increased. Producers must drill enough wells[19] to produce $Q_T/Q = R = (Q_1/Q)(1-R)^{T-1}$ where Q is the total output of the wells over the entire period, Q_T is the maximum output in the final year, R is the uniform rate of production

and T is the number of years specified in the contract. If the required uniform rate of production is (say) 2 per cent per annum for 21 years, then $Q_1/Q = 2.97\%$. However, a doubling of the uniform rate to 4 per cent requires a tripling of the initial capacity to 8.76% owing to pressure reductions in the field over time - clearly a case of diminishing returns and an offset to the higher prices available from increasing the uniform rate of production.[20]

Longer contract periods result in higher prices being paid to producers for the gas because of the extra costs involved (such as additional supervision wages and new tubing replacement each year). In addition, the longer payback period for the stock of gas available makes longer contract periods less attractive to producers.

Non-associated gas fields will have different per unit costs (for any given percentage recovery) depending upon the volume of gas in the reservoirs, the pressures in the reservoir (often a function of the depth of the well) and, finally, the amount of impurities in the gas (since maintenance costs increase with the amount of impurities). Fields of non-associated gas will have different costs from those in which both oil and gas are found. Tables 3 and 4 indicate that roughly 30 per cent of all gas reserves in the province are associated with, or dissolved in, oil reserves. For these supplies the most significant additional cost involved to collect the gas is the separator at the wellhead and - barring intervention by the Oil and Gas Conservation Board - this cost

will only be incurred if it pays to collect and sell the gas rather than vent or flare it.

The result of the foregoing analysis is, that in the short run at least, large amounts of gas are available at low (and varying) marginal costs. In selling this gas, field producers face oligopsonistic power. These factors plus the large number of small producers,[21] fairly homogeneous product and easy entry (relatively low capital requirements and the effects of "penny stock financing"[22]) argues against the existence of economic profits in the exploration and production stages.

To leave the impression that marginal costs of natural gas production are low would be superficial and misleading. Time is the missing dimension that needs to be brought out explicitly. While it is true that in the short run some factors are fixed - exploration and development costs must be incurred before the gas can be extracted - in the long run these factors are variable. After exploration and development costs have been incurred, the marginal costs to produce the gas are low and fall over quite a wide range of recovery levels. However the most easily accessible fields are located and exploited first. This means that, in the long run, costs of exploration and production will rise as deeper (and more costly) drilling is required and fields easily spotted by surface seepages are exhausted. It might be possible to conjecture that, over time, the industry might have decreasing - not increasing - per unit costs owing to: (1) the possibility

of larger discoveries from deeper drilling (that is, a negatively rather than positively sloped long-run average cost curve); (2) technological developments that have made it easier (and cheaper) to drill and to produce in a given field (that is, a downward shift of the long-run average cost curve). However, this second factor is outweighed by the increasing difficulty of finding fields[23] and there is no empirical support for the belief that larger reserves are located at lower depths. Finally too, it should be remembered that, while marginal costs in any one year for a given field are low, they tend to rise over the lifetime of the field as pressures decline and wells sand up or require secondary recovery techniques to maximize lifetime recovery from the reservoir.

In summary then, field producers are very competitive and face increasing costs, in the long run, as fields and individual reservoirs are depleted. Nonetheless, the very competitiveness and substantial rewards present for successful exploration (plus the randomness and unexpected nature of major discoveries) ensures rapid and insistent discovery of reserves. Under such circumstances, it is unlikely that economic profits exist in the finding stage of the industry although individual producers may be highly successful.

FOOTNOTES

[1]The reader is referred to the Glossary for definitions of all technical terms used.

[2]See Eric J. Hanson, Dynamic Decade (Toronto: McClelland and Stewart Limited, 1958), pp. 235, 237 for an analysis of the components of natural gas in selected pools in Alberta in 1957. It is interesting to note that Professor Hanson stated at that time (p. 235):

> As a rule, owners of gas wells cannot meet operational costs unless several components can be sold. Consequently, most gas wells in Alberta are capped and the development of known fields has been held back. This state of affairs will change once the two major pipe lines, one from the Peace River region and the other from southern Alberta, are completed.

This comment will be referred to again later in this thesis.

[3]6,000 cf. of gas (at 14.65 psia) equals the heat content of a barrel of oil (6 million BTU's). This is twice the energy content of manufactured coal gas (at similar pressures). Paul W. MacAvoy, Price Formation in Natural Gas Fields (New Haven and London: Yale University Press, 1962), p. 11 (text and footnote).

[4]Canadian Gas Association, "Geology of Natural Gas Production and Storage", What's Your Gas Q? Paper No. 9 of the Technical Education Committee of the Canadian Gas Association (undated).

[5]See Hanson, op.cit., pp. 118-22 for a discussion and numerical example of the factors relating to ultimate recovery from a reservoir.

[6]MacAvoy, loc.cit.

[7]Canadian Gas Association, loc.cit., Paper No. 4 "The Earth Beneath Us: Cosmic and Geologic Time".

[8]Hanson, op.cit., p. 32.

[9] M. A. Adelman, "The Supply and Price of Natural Gas", Supplement to the Journal of Industrial Economics (1962), p. 33. The reasons offered are that, first, greater pressures and heat act as a natural cracker to break down heavier paraffins into lighter ones and, second, that greater compression causes more gas to exist per cubic foot of permeable rock and sand.

[10] Brian Hitchon, "Geochemistry of Natural Gas in Western Canada", reprinted from Natural Gases of North America - Memoir No. 9, II (The American Association of Petroleum Geologists, 1968), pp. 2016-17. I am grateful to Dr. Hitchon for his patience in assisting me at this point of the paper. It should perhaps be stressed that the presentation here only relates to certain geological variables considered to be key ones for the economics presented later in this paper and is not intended to be a comprehensive or exhaustive treatment of the subject. No errors contained herein should, however, be attributed to Dr. Hitchon.

[11] Hitchon, op.cit.

[12] George H. Sutherland, Functional Analysis of Oil and Gas Industry in the Northwest Territories (Ottawa: Department of Indian Affairs and Northern Development, 1970), pp. 5-11.

[13] A reflection seismograph measures the speed at which sound travels through the earth. Explosions on the earth's surface reflect off rocks in the ground and thereby indicate the thickness of sedimentary rocks (sound travels slower through the softer sedimentary rocks) and the presence of structural faults and unconformities which may have trapped oil and gas. A gravitymeter is not as sophisticated but measures the gravitational pull of rocks below the surface - different rocks having different specific gravities and, therefore, varying gravitational pull. Hanson, op.cit., pp. 112-14.

[14] The Financial Post, Survey of Oils, 1970 (Toronto: McLean-Hunter Limited, 1970), pp. 28-29.

[15] Ibid, 25-26.

[16] Effective June 1, 1971 the name of the Oil and Gas Conservation Board of Alberta was changed to the Alberta Energy Resources Conservation Board. The former name will be adhered to in this thesis.

[17]In January, 1970 the Oil and Gas Conservation Board of Alberta approved the export of 1.54 Tcf. of gas by a new company, Consolidated Natural Gas Limited. However, this company (a subsidiary of a U.S. company - Northern Natural Gas Company) was, in August, 1970 denied permission to export this gas from Canada and denied permission to build a trunk line (36-inch) to the United States. This company's impact on Alberta's gas industry to date has thus been confined to bidding against Trans-Canada Pipe Lines Ltd. in the Strachan-Ricinus area and Kaybob South field. The entry of this company is further substantiation of the U.S. gas shortage and is discussed further in Chapter III.

[18]MacAvoy, op.cit., pp. 37-47.

[19]Wells in a field or reservoir are not all drilled when production first begins (as Fig. 3 and the surrounding discussion in Chapter III indicates and the example of the Medicine Hat field in Appendix I illustrates). MacAvoy, op. cit., pp. 12-14, seems to leave the impression that, after the initial successful wildcat well is completed, the field is about 20 to 40 per cent developed before a sales contract is signed and then virtually all wells are then drilled (and compression equipment installed) before production commences. This is somewhat inaccurate (at least for Alberta) but is a useful conceptual simplification in the present discussion.

[20]Ibid, 13-14.

[21]At the end of 1962, the Dominion Bureau of Statistics listed 180 firms producing crude petroleum and natural gas in Alberta. Of these 180 firms, there are 67 listed as producing in "various" fields or locations. The term "various" seems to mean "more than three". Dominion Bureau of Statistics, The Crude Petroleum and Natural Gas Industry, 1962 (Ottawa: Queen's Printer, 1966), pp. 19-21. At the end of 1968 the number of establishments had risen to 233. Dominion Bureau of Statistics, op.cit., 1968, p. 8.

[22]It is the author's (unproven) belief that small exploration companies in this industry probably have lower returns than they would if it were not for the "penny stock" financing and the heavy acceptance of risk (relative to comparable rewards in industrial stocks) that small "investors" seem to be willing to take. It is probably not uncommon for small investors to buy penny stocks with low expected returns (on average) since (1) they can buy a respectable amount of stock - 500 or 1,000 shares - for only a few hundred dollars (as opposed to only 10 or 20 shares of a large industrial company for the same dollar amount) and (2) the boundless

enthusiasm and hope that makes these investors think in terms of $20.00 per share for their (probably worthless) penny stocks. This belief would seem to be in accord with the Friedman-Savage expected utility hypothesis which states that people may be prepared to accept a lower expected average return for the possibility (perhaps small) of a large gain. See Milton Friedman and L. J. Savage, "The Utility Analysis of Choices Involving Risk", Journal of Political Economy 56, (August, 1948).

[23] Reference to the Statistical Yearbooks of the Canadian Petroleum Association indicate a clearly declining percentage of wildcat wells that result in "significant" finds (1 million barrels of crude oil or crude oil equivalents based on a value basis) for Alberta and Western Canada as a whole for the period 1947 to 1969. The years 1967 to 1969 have however been above the 23 year average of 6.19 per cent for Western Canada as a whole. These three years are the first time since 1953 that the percentage of significant discoveries has been above the long run average. Canadian Petroleum Association, Statistical Yearbook, 1969 (Calgary, Alberta: 1970), p. 23.

CHAPTER II

PROBLEMS OF COST ANALYSIS

Joint Supply and Joint Cost

Joint costs are incurred when production of one commodity results in the simultaneous and unavoidable production of one or more other commodities. The concept of average total cost for one of the products loses significance under these circumstances, although marginal costs may still be defined.[1] A necessary and vital distinction is whether the two (or more) products are produced in absolutely fixed proportions (the classic example is beef and hides) or can be produced in variable proportions - at least within a range of output. A further important distinction for output equilibrium conditions is whether production occurs under monopolistic or purely competitive conditions. Finally, joint costs should not be confused with common costs which refer to the production of goods in the same facilities although the goods themselves are technically independent and need not necessarily be produced together.[2]

In the joint supply case, many of the costs incurred can only be allocated in some arbitrary way. Natural gas is found and produced to a considerable degree jointly with crude oil and/or condensates. The importance of fair and proper cost allocations has been highlighted in the United States where, since 1954, the field price of natural gas has been regulated by the Federal Power Commission.[3] The varying ways in which costs are allocated has been summarized by

C. F. Phillips, Jr. as follows:

> Three allocation methods have been widely employed. (1) Sales Realization. Annual costs, including operating expenses, depreciation, depletion, exploration, and development, are allocated in proportion to the revenues received from the products during the test period. Fixed costs, including net plant and working capital, are allocated in proportion to the value of the reserves remaining in the ground in the test period. (2) Btu. Method. Joint costs are allocated in proportion to the British thermal unit content (i.e., the energy content) of the products. (3) Relative Cost Method. The joint costs of gas and oil are divided in proportion to the costs of the two products in pure gas and pure oil wells. Each of these methods has serious weaknesses. Moreover, since all allocation methods are partly arbitrary, so are the resulting "cost" figures.
>
> . . . .
>
> The Btu. Method is most often used to allocate exploration costs; the Relative Cost Method to allocate production costs. The two separate allocation methods are used because production costs can be more readily identified with a particular type of production (or lease type), whereas exploration costs (such as geological expenditures) are more general and are therefore said to be incurred "in the indiscriminate search for hydrocarbons". However, in the Area Rate Proceedings ..., the FPC [Federal Power Commission] accepted the "directionality" thesis, namely, that producers can direct their exploration efforts towards oil or gas and can assign certain costs respectively.[4]

Before discussing the extent to which costs can, in fact, be separated, the theory of joint costs as applied to the petroleum industry should be clearly understood.

<u>The Fixed Proportions Case</u>

For two commodities[5] X_1 and X_2, output equilibrium under purely competitive conditions will exist when:

$$MC_{x_1+x_2} = ap_{x_1} + bp_{x_2} \tag{2.1}$$

where:

$MC_{x_1+x_2}$ = the marginal cost of X_1 and X_2

a = the proportion of X_1 produced

b = the proportion of X_2 produced

$a+b$ = 1 for the two products

p_{x_1} = the price of X_1

p_{x_2} = the price of X_2

If the products are non-competing, an increase in the price of (say) X_1 will cause the output of X_1 and X_2 to increase and the price of X_2 to fall - perhaps to the point where the marginal revenue of X_2 will be less than zero (under competitive conditions). If the products are substitutes, a rise in demand for X_1 will lead to price and output increases for both products. Since it is not possible to separate average costs for X_1 and X_2 individually, full competitive output equilibrium conditions may be expressed as:

$$p_{x_1}+p_{x_2} = MR_{x_1}+MR_{x_2} = MC_{x_1+x_2} = AC_{x_1+x_2} \quad (2.2)$$ [6]

where:

$AC_{x_1+x_2}$ = the average cost of X_1 and X_2 and the remainder of the notation is as previously described.

When monopoly conditions are present, the above equilibrium condition must be modified to take account of a negatively sloped marginal revenue curve and the condition that marginal revenue for each of the products not be negative. Thus:

$$p_{x_1}+p_{x_2}>MR_{x_1}+MR_{x_2} = MC_{x_1+x_2} \quad (2.3)$$

$$p_{x_1}+p_{x_2}\geq AC_{x_1+x_2}^{\;7} \quad (2.4)$$

$$MR_{x_1},\ MR_{x_2}\geq 0 \quad (2.5)$$

The Variable Proportions Case

As an illustration of the case where output of the products is variable, within a range, we continue the example of 2 commodities, X_1 and X_2, and assume 2 inputs - one variable (v) and the other fixed. Production of each commodity is then a function of the variable input and the amount of the other product produced. That is:

$$X_1 = f_1(v,X_2) \quad (2.6)$$

$$X_2 = f_2(v,X_1) \quad (2.7)$$

This yields:

$\frac{\partial X_1}{\partial v}$ = the marginal productivity of v when X_2 is held constant

$\frac{\partial X_2}{\partial v}$ = the marginal productivity of v when X_1 is held constant

A typical product transformation curve for any given level of input v will be concave to the origin and will not touch the axes (illustrating the fact that some output of both commodities is unavoidable).

Bringing costs into the analysis, we let FC denote the cost of the fixed input and the price of the variable input be g.

Total cost of the outputs then is:

$$TC = C(X_1, X_2) = gv + FC \tag{2.8}$$

It should here be re-emphasized that allocation of variable or total costs will be arbitrary. However marginal costs are not elusive and, whether one is considering changes in the composition of the output or changes in the quantity produced, the behaviour of marginal costs are (theoretically) separable and significant. Thus:

$$MC_{x_1} = \frac{\partial TC}{\partial X_1} = g\,\frac{\partial v}{\partial X_1} \tag{2.9}$$

$$MC_{x_2} = \frac{\partial TC}{\partial X_2} = g\,\frac{\partial v}{\partial X_2} \tag{2.10}$$

It is now possible to bring revenues into the analysis. The interrelationship between the prices of the products is given by:

$$p_1 = p_{x_1} = p_1(X_1, X_2) \tag{2.11}$$

$$p_2 = p_{x_2} = p_2(X_1, X_2) \tag{2.12}$$

Total revenue is expressed as:

$$TR = p_1X_1 + p_2X_2 = p_1(X_1, X_2)X_1 + p_2(X_1, X_2)X_2 \tag{2.13}$$

From this expression we obtain:

$$MR_{x_1} = \frac{\partial TR}{\partial X_1} = p_1 + \frac{\partial p_1}{\partial X_1}X_1 + \frac{\partial p_2}{\partial X_1}X_2 \tag{2.14}$$

$$MR_{x_2} = \frac{\partial TR}{\partial X_2} = p_2 + \frac{\partial p_2}{\partial X_2}X_2 + \frac{\partial p_1}{\partial X_2}X_1 \text{ [8]} \tag{2.15}$$

The marginal revenues of the two products are interdependent except when $\frac{\partial p_1}{\partial X_2} = \frac{\partial p_2}{\partial X_1} = 0$ and the demands for the

products are independent of each other. The profit function (π) is equal to total revenue minus total costs and, for a maximum, the first and second-order conditions are:

$$\frac{\partial \pi}{\partial X_1} = \frac{\partial \pi}{\partial X_2} = 0 \tag{2.16}$$

and:

$$\frac{\partial^2 \pi}{\partial X_1^2} < 0 \qquad \frac{\partial^2 \pi}{\partial X_2^2} < 0 \tag{2.17}$$

Therefore:

$$\frac{\partial \pi}{\partial X_1} = \frac{\partial TR}{\partial X_1} - \frac{\partial TC}{\partial X_1} = 0 \tag{2.18}$$

$$\frac{\partial \pi}{\partial X_2} = \frac{\partial TR}{\partial X_2} - \frac{\partial TC}{\partial X_2} = 0 \tag{2.19}$$

Sufficient total equilibrium conditions are:

$$MR_{x_1} + MR_{x_2} = MC_{x_1} + MC_{x_2} \tag{2.20}$$

$$p_{x_1} \geq MR_{x_1} = MC_{x_1} \tag{2.21}$$

$$p_{x_2} \geq MR_{x_2} = MC_{x_2} \tag{2.22}$$

Various possible production possibility paths (1, 2, 3, 4 and 5), cost curves (C_1, C_2 and C_3) and iso-revenue curves (R_1, R_2 and R_3) are shown in the diagram below.

The assumed linear shape of the iso-revenue curves below (with slope of $-\frac{Px_1}{Px_2}$) reflects purely competitive conditions. Under monopolistic conditions the functions would be non-linear. Also, the cost curves reflect the increasing costs of attempting to "squeeze" more of one product out of the inputs. On production possibility path 3 the marginal

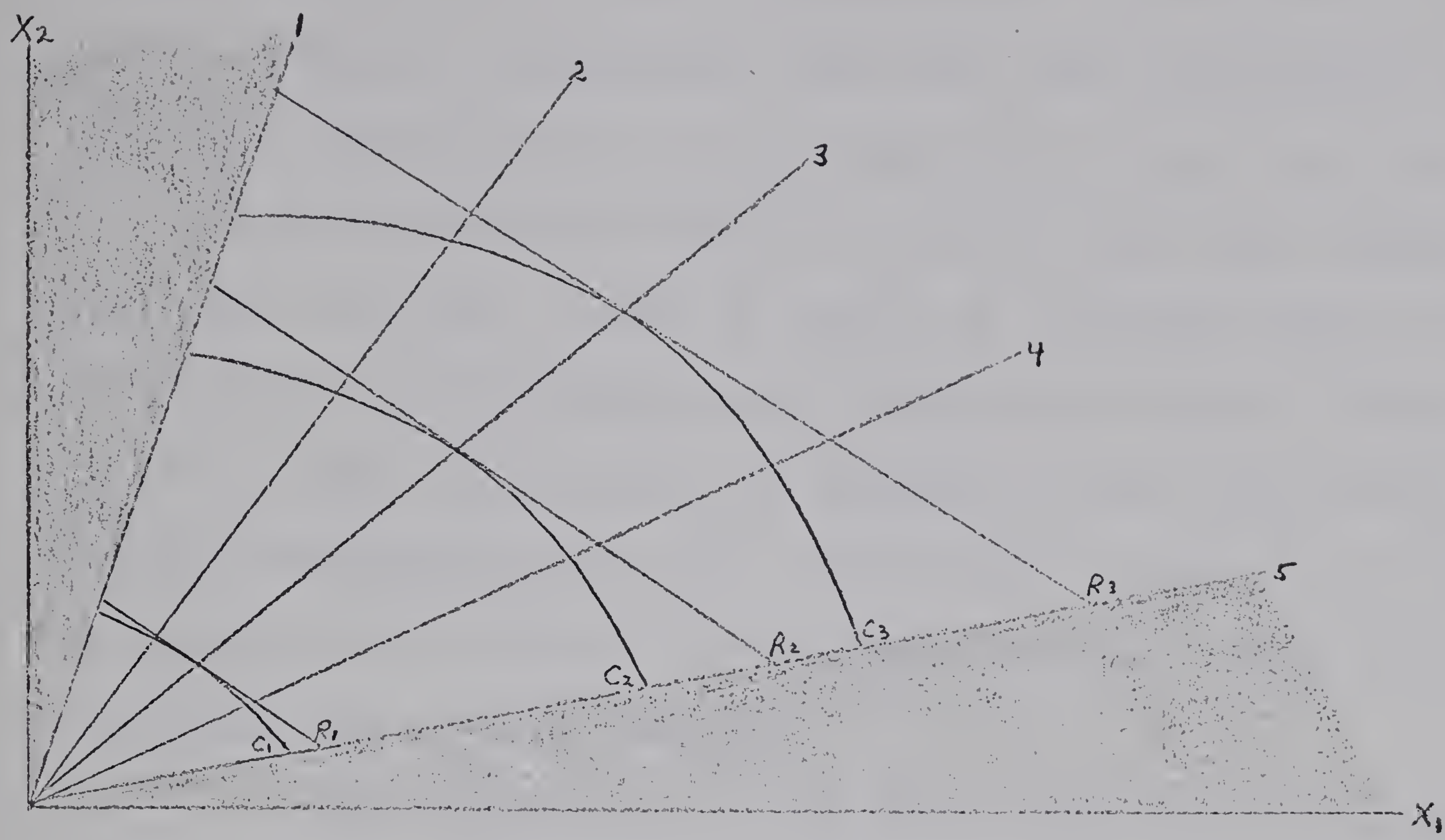

Fig. 2 Output equilibrium for an individual firm

rate of transformation of X_1 for X_2 is equal to the marginal rate of substitution in the market and an equilibrium results. A solution inside the feasible set has been assumed. It is, of course, possible that a firm would desire to operate in the shaded area but would be compelled to operate along production possibility path 1 or 5 owing to the technical constraint. In this case profits will be less than they would be without the constraint, and the foregoing analysis should be rephrased in terms of inequality conditions.

Separable Costs

It has already been mentioned in this chapter that the Federal Power Commission in the United States accepted the thesis that firms could direct their exploration efforts

towards either oil or gas. Furthermore, in the first chapter of this thesis, considerable time was spent developing data as to the formations in which either oil or gas was likely to be located and which of these formations were more likely to yield gas (or oil). Also it should be recalled that 70 per cent of all gas in the province is non-associated. Hence, there is ample opportunity to explore for gas and develop gas fields independently of oil. Even within fields the driller is aware that the deeper he goes the "wetter" the gas is likely to be and the lighter the oil.

Past experience is the best indicator of prospects in any area and, within the province, all operators have access to the results of every drill stem test and rock core test. The depth to any particular formation in an area is also known by exploration companies. Thus, while it is nonetheless true that "you can't tell 'till you drill", an operator does have considerable knowledge on which to base the geological evaluation of any project. The firm has an implicit (or perhaps, occasionally, even explicit) probability function in mind before it eventually makes the decision to drill. It knows what the chances are of finding either gas or oil and, occasionally, has some idea what the probable reserves are that may be found if the well does turn out to be a producer. Thus, the firm can begin to make an economic evaluation of the project and begin to estimate the possible revenues that may be obtained. Such revenues will depend greatly on whether gas or oil is sought and what the future price of the resource

discovered is likely to be. It will also be influenced by such factors as prorationing, taxes and lease and royalty payments.[9]

In making the economic evaluation of a project, price and revenues are only one side of the coin. The costs of exploration, development (if successful) and eventual production must be weighed and compared to future expected revenues. Finally, even if the project in question appears to be worth the risk, there are the constraints of funds availability (or funds rationing) and satisfaction of the various goals of the firm - both short run and long run. These constraints, coupled with the high probability of dry holes have resulted in a great number of joint ventures in the industry.[10]

Exploration costs can, therefore - in theory if not always in practice - be allocated to oil and/or gas. Even before going into an area, a firm knows (based on past experience of itself and others) the chance it has that a strike will be gas (or oil). As it proceeds through the various formations, the probabilities of oil, gas or water (or nothing) in the next formation will change. The eventual decision to abandon the well, rather than proceed further, is likely to be based more on past experience in deeper formations in that area than it is on the seismic work which is done as the drilling proceeds.

Exploration wells are generally classified as being: (1) new field wildcats; (2) new pool wildcats; (3) deeper

pool tests (allocated partly to exploration and partly to development); (4) shallower pool tests; (5) outposts. The crucial distinction (as far as this discussion is concerned) between these categories is the range of probabilities, associated with each type of well, of finding either oil or gas. The probability of finding gas (rather than oil) for any particular new field wildcat might range between, let us say, 60 and 80 per cent. The probability range for that same well if it were an "outpost" (more than 2 miles from a producing field and a "semi-development" type of well) might be somewhat greater and the range considerably narrower - for example, 80 to 85 per cent.

If time (and resources) had been available, there are two ways in which exploratory drilling costs could have been allocated to either gas or oil. The first (and most straightforward) method would involve examining drilling applications made by firms to the Alberta Oil and Gas Conservation Board. These applications state the reasons for drilling and what the firm hopes or expects to find. By reviewing the well files (or a sample of these files) it would be possible to determine the target zones for the wells and get a breakdown of the number of wells for which gas was the objective. Admittedly the wells may not yield the anticipated results but this method would provide the closest insight into intentions of firms at the point of investment decision.

The second method that could be used in allocating exploration drilling costs would be to review applications by

firms to the Alberta Department of Mines and Minerals for drilling reservations. Each application states the formation(s) which the firm wishes to test and, given the analysis in Chapter I, would enable a researcher to assign probabilities to the firm's intentions. For example, if the firm planned to test the Mississippian formations then (from Table 2) there is about a 95 per cent chance that the firm is looking for natural gas or natural gas liquids - not oil. Since (from Table 4) about 80 per cent of the gas reserves in the Missi-ssippian formations are non-associated, there is very little chance of oil being located in these formations - although surprises will occur from time to time.

Exploration costs (other than drilling) can also be allocated to either gas or oil. Petroleum and natural gas permits (also called reservations) are obtained from the Province of Alberta prior to exploratory drilling. If a commercial discovery is made, the reservation must then be converted to a lease (it can be converted to a lease at the option of the reservation holder even if commercial quantities are not found).[11] This lease covers up to 50 per cent of the land included in the permit. The remaining 50 per cent is auctioned by the province. If a holder of a permit or reser-vation determines the presence of natural gas through drilling, a natural gas license for the zone(s) containing the gas may be obtained. Natural gas leases may be obtained if the holder of the natural gas license delineates a field within the zone(s) specified.[12]

Natural gas leases and licenses are clearly assignable to natural gas discovery costs. The expenditures for petroleum and natural gas drilling reservations and leases must be apportioned in some selected manner. Time limitations did not permit assignment of reservations according to the geological zone specified in the applications (as discussed above). Another reasonable, albeit somewhat arbitrary, method of apportioning aggregate expenditures is a moving average of volumes of reserves discovered (gas and oil must be expressed in similar physical units such as volume or weight). Reserves in this method serve as a proxy for the directionality of search. A further possible "refinement" to this apportionment would be to use only non-associated gas reserves in the calculations since casinghead gas is largely a byproduct of the search for oil.

Geological and geophysical expenditures are more difficult to handle than permits and leases. There is no reason to assume that it costs the same amount per acre to survey a gas-prospective area as compared to an oil-prospective area. Without more disaggregated data, an apportionment similar to the one proposed for leases and reservations is almost mandatory. Overhead and other general costs of exploration firms (or exploration divisions of larger firms) must also be allocated in a similar manner - although, ideally, these too can be allocated to the search for either gas or oil. Possible "padding" of exploration costs with overhead expenses is a danger in any cost analysis as firms may attempt to obtain income tax benefits from so doing.

TABLE 7

COMPONENTS OF COSTS OF DRILLING WELLS

1. Exploratory Wells - Initial

   (a) Materials and equipment

      (i) Casing (lightweight steel pipe approximately 30 feet in length used to prevent cave-ins and to shut off oil, gas or water);

      (ii) Cement in which the casing is set to permanently shut off water;

      (iii) Liquid mud from the sump pit which is pumped down the hollow drill pipe, through holes in the drilling bit and back up to the surface where it is cleansed of rock cuttings and then recycled;

      (iv) Drill stem consisting of drill pipe, drill collar and bit (usually rotary bits are used) rotated by the rotary table;

      (v) Draw works - the operating machinery such as the hoisting drum, shaft and clutches receiving power from the engine;

      (vi) Rotary table driven by chain from the draw works;

      (vii) Derrick (steel) which supports the drilling apparatus;

      (viii) Other materials and supplies such as electrolog supplies, mud conditioner, fuel and power, grease, oil, explosives, displacement oil, diamond coring to about 80 ft. depth, scratchers and centralizers, etc.

   (b) Labour and professional fees

      (i) Drilling labour and supervision;

      (ii) Cementing services, electrologging, welding of steel casing, and geological services such as rock core analysis and drill stem tests;

      (iii) Consulting engineers;

      (iv) Surveying of site, roadwork, etc.

--continued--

TABLE 7 (continued)

(c) Other

(i) Trucking and freight;

(ii) Insurance;

(iii) Taxes;

(iv) General overhead;

(v) Miscellaneous (all other costs).

2. Exploratory Wells - Completion costs

(a) Materials and equipment

(i) Casing from about the 300 foot mark to the pay zone (casing pipe narrows in size as hole is drilled deeper);

(ii) Tubing installed to the producing horizon;

(iii) Jet perforation and acidizing (increases permeability);

(iv) "Christmas tree" (producing head);

(v) Miscellaneous supplies.

Source: E. J. Hanson, Dynamic Decade (Toronto: McClelland and Stewart Limited, 1958), pp. 132-140.

Table 7 indicates cost components in drilling wells. It should be noted that additional expenditures (e.g., casing and tubing) are required to complete a producing well. Developing a field or reservoir properly commences at this point. Cost allocation is less arbitrary at this stage - and later ones.

If gas were worthless, no completion costs or development expenditures would be incurred. A well locating only non-associated gas would be abandoned (capped). The same is true for oil pools with either water or pump drive. The occurrence of oil and gas together presents problems in cost allocation. As Professor M. A. Adelman puts it:

> The jointness of cost is very different as between non-associated gas and "casinghead" gas (associated and dissolved). Dissolved gas is rigidly, and associated gas is largely, in fixed proportions at every stage through actual extraction. The producer has no option but to find, develop and bring them up together; discretion only begins when he decides whether to gather the gas or to vent and burn it. Only to the limited extent that exploration can be varied somewhat, or a gas cap left untouched or reinjected for pressure maintenance to be sold after much of the crude is produced, can we speak of variable proportions. Otherwise, there is no marginal cost of "casinghead" gas apart from oil, or oil apart from "casinghead" gas; doubling the output of one doubles the output of the other, etc. The only price that can affect output is the price of gas-plus-oil.[13]

Thus, while all costs of completion and development for a non-associated gas reservoir are marginal costs, the discussion of joint costs at the beginning of this chapter indicated that for the fixed proportions case (e.g., dissolved gas[14]) there is only one marginal cost (2.1). For the variable proportions case, the marginal costs can be separated but only within a range. Everything depends on the method by which the reservoir is developed. If all gas is reinjected for pressure maintenance, and never recovered, then the costs to complete and develop are properly attributable to the oil. If the gas is all vented or flared, again there is no marginal cost attributable to the gas. However, if the producer installs a

gas:oil separator and related gas gathering facilities, then it becomes important how the costs are allocated. Since the decision to produce the oil may depend partly on the fact that the gas can be sold, the variable costs are properly assignable. To attempt to allocate the fixed costs though would result in a return to arbitrariness.

Basic Cost Categories

Table 7 set forth the various components in the costs of drilling wells. Well costs though are only one component of the total cost of field gas. At this point it is necessary to state exactly what is defined (in this paper) as belonging to each of the various cost categories.

The definitions of Hodges and Steele, as summarized by Lovejoy and Homan, provide a useful and logical starting point. They state:

> Finding (or exploration) costs
>
> a. Lease acquisitions.
>
> b. Geological and geophysical expenditures.
>
> c. Drilling costs of all exploratory wells, whether dry or successful.
>
> d. Completion cost of successful exploratory wells through installation of the Christmas tree.
>
> Development costs
>
> a. Equipment cost of successful exploratory wells (flow lines, storage tanks, etc.) beyond the Christmas tree.
>
> b. Drilling costs for all subsequent wells, whether productive or dry, including drilling to define the limits of the pool.
>
> c. Field development outlays.

d. Capital expenditures for pressure maintenance and secondary recovery projects.

Production costs

Current operating outlays made to secure production from existing wells, including

a. Pumping or other lifting costs.

b. Field maintenance and upkeep costs, not including capital expenditures on secondary recovery and the like, which are included in development costs.

c. Certain leasing and other land-use outlays.

To each of these categories an overhead cost must usually be allocated.[15]

An immediate and important difference between this framework and the theoretical one established in this chapter is that completion costs of successful exploratory wells are considered by Hodges and Steele to be part of exploration costs but, since they are clearly not incurred unless the exploratory results warrant it, they must be considered development costs. Data sources allocating completion costs in this way are, therefore, considered superior to those which do not do so.

Leases are in the nature of economic rents to land-owners and must be treated carefully. Economic rents are generally the difference between total revenues and total variable costs that accrue to the owners of resources purchased (or hired) by the firm. The difference between total revenues and total variable costs that accrues to the firm itself is available to cover the fixed costs (rents to others for resources they own) and "pure" profit (as distinct from "normal" profit which is imputed as one of the fixed costs to capital -

a factor of production). Economic rents accrue to the owners of oil and gas reserves because oil and gas producers bid for leases. Having acquired these leases and rights, the firms then attempt to earn economic profits in the face of uncertainty and the lack of complete knowledge that exists during a great part of the time that a reservoir is being developed. These lease payments thus become part of the costs of bringing gas to the market and - to some extent - of bringing it to the market by a number of firms in the exploration stage of the industry.[16] Economic rents will thus accrue to the Province of Alberta (and other landowners) and not to the producing firms. In treating these lease costs, it is necessary to apportion them carefully according to the stage to which they apply. This includes the development stage and should have been itemized explicitly in the above framework. Land holdings and leases will be dealt with further in Chapter III.

The remainder of the cost framework developed by Hodges and Steele is fairly straightforward. The inclusion of dry wells in development drilling is an important one and constitutes a great improvement over the arbitrary method of many studies in the past which allocated all dry wells to exploration and all productive wells to development. Such a method is clearly unsatisfactory for, as Lovejoy and Homan, have put it:

> Granted that the line between exploratory and development drilling is blurred, the nature of development drilling is different from wildcat drilling, and such things as costs and risks are substantially at variance. It seems more logical to put dry holes drilled in defining the limits of a pool in the

development category and to put productive wells from wild-catting operations in the finding category. In any case, a uniform plan of reporting is needed.[16]

A final point to be noted is that in the development of gas fields, processing plants must be installed. Capital costs for these plants should be assigned to development costs but operation of the plant is a production expense.

These cost categories are utilized in Appendix I which analyses the costs to develop the Medicine Hat gas field (using only published data). This sample calculation is designed to provide some idea of the possibilities and problems involved in published data - a topic discussed later in this chapter. An attempt is made in the appendix to estimate drilling costs in the field by using an exponential relationship of well drilling costs to depth as developed in the United States. This is a particularly difficult task given the highly aggregated (although good) data available. An attempt at greater precision in the estimates was beyond the scope of this analysis. Also, it should be mentioned that the Medicine Hat field - although large - is one of the easiest to analyse because no joint costs with oil are involved. However the method used does provide what appears to be a fairly accurate estimate of costs to develop the field (in terms of cents per Mcf.).

Economic Cost and Replacement Cost

The calculation of economic cost "requires the isolation of all costs, past and current, capital and operating, which are properly attributable to current production".[18]

For practical purposes such a calculation is usually impossible. Therefore, another method - replacement cost - is usually used to approximate economic cost of current production.

The replacement cost of a barrel of oil or an Mcf. of gas is an attempt to relate supply to costs. Basically, the method adds current production costs per Mcf. of gas (or per barrel of oil) plus development costs per Mcf. (development outlays divided by "extensions" and "revisions" to reserves) plus current finding costs per Mcf. The resultant "cost" figure, if it properly allows for jointness between oil, gas and gas liquids, is the replacement cost of an Mcf. of gas. But replacement cost does not tell us how much it costs for an Mcf. of gas this year. Only the production costs fit the test of currentness. Finding and development costs, however, apply to future production in a widely varying and uneven manner. The problems and potential biases in using reserves figures are significant too. In fact, one of the great advantages to looking at costs for various fields (and discounting costs over time) is that reserves data are largely unnecessary. The immediate problems with using reserves data are, as Bradley points out, that:

> Though carefully framed, definitions of reserves are arbitrary. For example, reserves are defined by the American Petroleum Institute in terms of the crude recoverable under existing technology and economic conditions. Ultimate reserves of a given reservoir therefore can change at any time because of new inventions or new price levels. Furthermore, in practice the estimated reserves of a given field show large increases as time elapses and more information is obtained. Changes are introduced through 'extensions', which reflect the results of additional development drilling, and through 'revisions', which

> may result either from better knowledge of the formation or improved production techniques.[19]

Replacement cost, as developed above, has two merits. First of all, changes or trends over time in the figure developed (and particularly the finding cost component) are highly significant. Second, in attempting to derive economic costs for gas, a modified replacement cost which lagged finding and development costs according to some average time between expenditures and production might work reasonably well - particularly if costs are discounted over time.

Industry Data-Availability and Quality

Table 8 describes the published data which is available for the Alberta natural gas industry from the Canadian Petroleum Association, Oil and Gas Conservation Board of Alberta and Dominion Bureau of Statistics. The only other major sources of data are the Financial Post's Survey of Oils and Corporation Service and the various trade journals such as Oilweek. Most of the data available in the Survey of Oils is repeated from other published sources (such as the Dominion Bureau of Statistics). The Corporation Service presents financial information (derived largely from annual reports) and the corporate history for public companies in the industry. Oilweek presents articles on topics of special concern for the industry. Its annual review issue contains data drawn largely from the Dominion Bureau of Statistics and the Canadian Petroleum Association.

Good information is available for reserves, drilling

(and drilling results), expenditures (both capital and operating), production and sales (supply and disposition) and the processing, transmission and local utility stages of the industry. Two important omissions in the data are:

(1) price series for new contracts and average wellhead prices;

(2) profit series - by industry stages - including revenues and costs (particularly depreciation).

Other problems that exist in the data (such as changes in classifications, changes in presentation and the aggregation of well depths - which is dealt with in Appendix I) will be mentioned in the appropriate places.

TABLE 8

PUBLISHED DATA AVAILABLE FOR ALBERTA - SELECTED SOURCES

Information	Canadian Petroleum Association	Oil and Gas Conservation Board of Alberta					Dominion Bureau of Statistics	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
<u>Expenditures:</u> Operating								
Field and well operations	√						√	
Processing plants	√						√	
Royalties	√						√	
Taxes (other than income tax)	√						√	
Land retentions and acquisitions	√						√	
Materials, supplies	√						√	
Interest and overhead	√						√	
<u>Expenditures:</u> Capital								
Geological and geophysical	√						√	
Exploratory Drilling	√						√	
- Dry	√							
- Producing - gas	√							
- oil	√							
Development Drilling	√						√	
- Dry	√							
- Producing - gas	√							
- oil	√							
Oil field facilities	√						√	
Gas field facilities	√						√	
Total field facilities	√						√	
Secondary recovery	√						√	
Natural gas processing plants	√						√	
Other buildings and machinery	√						√	
Land sites	√						√	
Land acquisition	√						√	

--continued--

TABLE 8 (continued)

Information	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Reserves								
Detailed by reservoir, type of gas, heating content, year of discovery, average well depth and physical characteristics of reservoirs, etc.		√						
As added during year, as to original in place, ultimate, ultimate marketable (all proved and probable), by year of discovery and geological age.	√							
Drilling Activity								
All-By type of well (number and footage)	√		√	√				
Successes-By type (number and footage)	√		√					
Significant Discoveries	√							
Supply								
Production by reservoir and field			√	√				
Production by month	√		√					
Detailed supply			√	√			√	√
Detailed supply by month			√					
Establishments and production activity (value added, wages, etc.)							√	
Value of shipments							√	
Net production withdrawals							√	
Production employment (by month)							√	√
Sales of gas by type of customer (including exports and imports)	√			√				√

--continued--

TABLE 8 (continued)

Information	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
<u>Supply</u> (continued)								
Supply of marketable gas to pipelines			✓					
Supply (and disposition) of products			✓	✓				
<u>Disposition</u>								
Detailed			✓	✓			✓	✓
Local utilities (revenues, financial information, monthly sales, underground storage, employees, earnings, etc.).								✓
<u>Pipelines</u>								
Mileage by type of line								✓
By size of pipe and type of line								✓
By company details (owner, point of origin, destination, miles of line, throughputs, capacities, markets served, size of pipe, source of gas, etc.).	✓							
Compressor stations								✓
<u>Processing Plants</u>								
Receipts and disposition of individual plants (by product)			✓					
Process shrinkage by plant			✓					
Owners, location, principal products and start-up date	✓		✓					

--continued--

TABLE 8 (continued)

Information	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Wells								
By field and formation type			√					
Capable wells - for major fields only				√				
Information - technical					√			
Other								
Salaries and wages (by type of employment)							√	
Permits information				√				
Future estimates of supply and requirements						√		
Crown land sales and estimates of acreage holdings by owner	√							
Survey crew months	√							

Sources:
(1) Statistical Yearbook, Annual issues to 1969.

(2) Reserves of Crude Oil, Gas, ..., annual issues to 1969.

(3) Summary of Monthly Statistics, annual issues to 1970.

(4) Cumulative Annual Statistics, annual issues to 1969.

(5) Schedule of Wells Drilled.

(6) Report on an Application ... Under the Gas Resources Preservation Act, periodically issued.

(7) The Crude Petroleum and Natural Gas Industry, annual issues to 1968.

(8) Gas Utilities, annual issues to 1967.

FOOTNOTES

[1]Kenneth E. Boulding, Economic Analysis (3rd ed., New York: Harper and Brothers, 1955), pp. 227, 769-70.

[2]James M. Henderson and Richard E. Quandt, Microeconomic Theory: A Mathematical Approach (Toronto: McGraw-Hill Book Company, 1958), p. 67.

[3]Charles F. Phillips, Jr., The Economics of Regulation (Rev. ed., Homewood, Illinois: Richard D. Irwin, Inc., 1969), pp. 602-4.

[4]Ibid, 605 (text and footnote). The author [pp. 611-13] explains the adoption in 1965 by the FPC of a two-price system. A separate and higher price for new non-associated gas was established to stimulate exploration activity for gas and to encourage companies to direct their activity toward gas. This higher price for new non-associated gas was deemed necessary since costs of exploration and development had risen sharply since World War II. At the same time it was felt to be unnecessary to grant the higher price for casinghead gas which results from the successful search for oil.

[5]The following analysis follows closely the exposition in Clark A. Hawkins, The Field Price Regulation of Natural Gas (Tallahassee: Florida State University Press, 1969), pp. 169-79.

[6]Ibid, 170. Hawkins gives $MC_{x_1+x_2} \geq AC_{x_1+x_2}$ but clearly this is not long run atomistic competition and, in the short run, there is no reason to assume that losses will not be incurred.

[7]Ibid. Hawkins gives $p_{x_1}+p_{x_2} > AC_{x_1+x_2}$ but, even in the long run, there is no reason to assume that monopolists will earn excess profits and, in the short run, losses may, in fact, be incurred.

[8]Ibid, 174. Hawkins gives the last term of this expression as $\frac{\partial p_1}{\partial X_1} X_1$ but that is incorrect.

[9]A good presentation of the decision process of drilling companies is given by C. Jackson Grayson, Jr.,

Decisions Under Uncertainty: Drilling Decisions by Oil and Gas Operators (Cambridge, Mass: Harvard University Graduate School of Business Administration, Division of Research, 1960), esp. Chpts. 4-7.

[10]About one-half of all wells drilled in Alberta recently have been dry and about two-thirds of all exploration wells have been dry (Canadian Petroleum Association, Statistical Yearbook, recent issues). This compares to 88% of all wells in the U.S. being dry (Hawkins, op.cit., p. 185). The losses incurred on dry holes form part of the overall costs to the industry but the risk to smaller independents is much greater.

Using the 1970 edition of the Financial Post's Survey of Oils, the share prices of all oil and gas companies (other than preferred and special classes) were examined for the period 1963 to 1969 to see how many had sold at a high of less than $5.00 per share in 1963 and a high of $5.00 per share or more in 1969 - $5.00 per share being arbitrarily considered as an indication of a successful producing company. Companies whose shares were not trading in 1963 were also included (even though they may represent reorganizations of previously successful companies and therefore overstate the degree of success for the "penny" oil and gas companies). In the seven year period there were 57 companies achieving this arbitrary standard of success - a fairly small number relative to the 300 or so companies that became defunct during the same period and the 33% success rate for exploratory wells drilled.

[11]See Hanson, op.cit., Chapter 16 and John E. H. Conder, "The Disposition of Crown Petroleum and Natural Gas Rights in Alberta", (unpublished Master's thesis, Department of Economics, University of Alberta, 1963), Chapter 3.

[12]Conder, op.cit., pp. 50-51. In terms of aggregate revenues, natural gas licenses and leases have been relatively unimportant.

[13]Adelman, op.cit., p. 29.

[14]There is, of course, the option with dissolved gas of venting (or flaring) the gas or collecting it. The separator required is part of the one marginal cost but the choice of collecting or dispersing the gas allows for a small theoretical adjustment to marginal cost calculations. Essentially there is only one marginal cost.

[15]J. E. Hodges and H. B. Steele, An Investigation of the Problems of Cost Determination for the Discovery, Development, and Production of Liquid Hydrocarbon and Natural

Gas Resources (Houston: Rice Institute Pamphlet, Vol. XLVI, No. 3, 1959), pp. 1-2 as summarized by Wallace F. Lovejoy and Paul T. Homan (with Charles O. Galvin), Problems of Cost Analysis in the Petroleum Industry (Dallas: Southern Methodist University Press, 1964), p. 13.

[16] If oil and gas producers did not compete with each other for leases, the industry could acquire rights at a much lower cost - presumably the nuisance cost to private owners of the oil and gas-producing lands of having firms drill on their land. However, the fact that the provincial government owns almost 85 per cent of the oil and gas rights allows it to exert some power in selling these rights - subject, of course, to the usual constraints on public policy (such as the desire to stimulate employment).

[17] Lovejoy and Homan, op.cit., p. 14.

[18] Ibid, 17.

[19] Paul G. Bradley, The Economics of Crude Petroleum Production (Amsterdam: North-Holland Publishing Company, 1967), p. 9. The Canadian Petroleum Association publishes reserves data similar to that of the A.P.I. and these comments therefore apply to Canada as well. Also, the Oil and Gas Conservation Board publishes reserves data, classifying reserves as being either within or beyond economic reach. These reserves estimates are very difficult to make - especially when every organization has a vested interest in the results. Another problem with the reserves estimates is that the Oil and Gas Conservation Board is dependent to a very great extent on information supplied by firms. If the firms do not report the expected full extent of a new find (and thereby gain some advantage in bidding for nearby land) the Oil and Gas Conservation Board estimates will be unduly low.

CHAPTER III

INSTITUTIONAL CONSTRAINTS ON THE INDUSTRY

The "Exportable Surplus" Policy

Both the National Energy Board and the Alberta Oil and Gas Conservation Board require that exports - from Canada and from the Province of Alberta respectively - come from reserves that are surplus to reasonably foreseeable requirements. A host of problems is created in evaluating trends in the discovery of gas and in estimating future demands for gas and its substitutes.

In principle, the policies of both the National Energy Board and the Oil and Gas Conservation Board are similar and applicants to the National Energy Board must first obtain permits to remove gas from the Province of Alberta. The policies of the National Energy Board - and, in particular, the changes resulting from the August, 1970 decision to permit exports of 6.3 Tcf. of gas - will be presented first. The policies of the Alberta Oil and Gas Conservation Board (and the changes resulting from its 1969 review of policies concerning exports of surplus) will be dealt with in later sections. Other institutional constraints on the industry are presented at the end of the chapter.

The effect of the recent changes by both the National Energy Board and the Oil and Gas Conservation Board has been to stimulate greatly exploration and development of gas in the Province of Alberta.

Setting of "Exportable Surplus" and Export Prices by the National Energy Board[1]

Section 83 of the National Energy Board Act of 1959 states the conditions for granting of a license as follows:

> Upon an application for a license the Board shall have regard to all considerations that appear to it to be relevant and, without limiting the generality of the foregoing, the Board shall satisfy itself that:
>
> (a) the quantity of gas or power to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirement for use in Canada having regard to the trends in the discovery of gas; and
>
> (b) the price to be charged by an applicant for gas or power exported by him is just and reasonable in relation to the public interest.

In 1969 the policy of the Board was not to allow additional exports unless it was satisfied that a surplus existed when:

(1) "available" reserves (including "contractable" reserves and existing import license volumes) were sufficient to meet 25 times the estimated fourth year Canadian requirement; and

(2) "future" reserves (including both contractable reserves and 20 years growth in reserves of gas initially in place[2]) were sufficient to meet expected requirements in Canada for the next 30 years (including peak day protection in the 30th year).

The definitions of "established" reserves and "contractable" reserves are important to note in connection with changes made in 1970. "Established" reserves consisted of proven reserves and up to 50 per cent of probable reserves.

In this sense, the established reserves were those that could reasonably be counted upon to exist in the volumes estimated. "Contractable" reserves consisted of established reserves less all reserves deemed to be beyond economic reach or unavailable for reasons of conservation. These reserves, then are those for which a purchaser is able to contract, with delivery commencing within 4 years. Alberta requirements (present and future) were set according to the policy followed by the Alberta Oil and Gas Conservation Board.

In the August, 1970 decision, an expansionary effect was generated by the liberalization of the methods used to calculate contractable reserves. A full 50 per cent of reserves categorized as beyond economic reach were included and the Board also included deferred reserves from which production is likely to occur in the next few years. Future Canadian requirements were, however, to be protected in the same manner as had previously been used (25 times the fourth year requirements).

The setting of a price that is "just and reasonable in relation to the public interest" by the National Energy Board is a crucial - and difficult matter for investment decisions in the industry. The Board has three criteria for determining the reasonableness of price:

(1) the export price should cover all relevant costs including a fair return on the whole capital investment;

(2) the export price should be fair in relation to the prices charged to Canadian distributors in the area

adjacent to the point of export (allowing for differences in the terms of sale);

(3) the export price to foreign buyers should not be greatly less than the price (or opportunity cost) of alternative sources of fuel to those customers.[3]

The first test was best satisfied in the August, 1970 decision by the cost of service arrangements of the Alberta and Southern Gas Co. Ltd.[4] The second test was best satisfied by the provision in the Trans-Canada Pipe Lines Ltd. contract that export prices be not less than 105 per cent of the regulated Manitoba price.[5] Clearly, however, neither of these arrangements can be assumed to satisfy the "opportunity cost" test and, while the Board was able to satisfy itself concerning the first two criteria reasonably well, severe problems resulted in tackling the third test.

In the consideration of export prices to be charged by Alberta and Southern, the Board found "considerable force in the logic by which the Applicant seeks to demonstrate that the third test is not usefully applicable to an export based on cost of service, but that the justness and reasonableness of the export price in such a case must be adjudged in the light of the evolution of the prices over the history and foreseeable future of the project".[6] Although the Board was unable to conclude that the third test had been met,[7] and believed, furthermore, that "the cost of alternative sources of energy for the California market may rise more sharply in the next few years than will the average cost of Canadian gas delivered to

that market",[8] and that "there is ... some gap [not easily quantified] ... [which], represents a subsidy by Canada to the United States consumers of the gas",[9] it approved the export price rather than upset an amicable trade arrangement which had been stimulating to the Canadian natural gas industry.[10]

The low export prices approved (relative to the "opportunity cost" criterion) were not the sole expansionary forces of the August, 1970 decision. Table 9 summarizes the volume reductions made by the National Energy Board in the applications of the various companies. The two most important points to be noted are:

(1) although volumes (in all cases except for Westcoast) were reduced, the number of years over which these volumes were to be exported was reduced so that the revised volumes were the same per year as they had been in the original applications;

(2) of the total reduction of 2,593 Bcf., almost 60 per cent was due to the rejection of the application of Consolidated Natural Gas Limited and Consolidated Pipe Line Company for reasons which may easily change within the next two to five years,[11] and thus generate greatly increased exports to the United States.

The Effect of the August, 1970 Decision by the National Energy Board

There are many conclusions - both charitable and uncharitable - which one may make regarding this decision by the Board and the acceptance announcement by the Minister of Energy,

TABLE 9

SUMMARY OF EXPORTS ALLOWED BY THE NATIONAL ENERGY BOARD DECISION OF AUGUST, 1970

Company	Applied for		Approved	
	Quantity (Bcf. at 1,000 BTU/cf.)	Years	Quantity (Bcf. at 1,000 BTU/cf.)	Years
Alberta and Southern Natural Gas Co. Ltd.	1,592	23	1,038	15
Canadian-Montana Pipe Line Company	86	23	56	15
Consolidated Natural Gas Limited	1,545	25	-	-
Trans-Canada Pipe Line Limited	2,336	25	1,872	20
Westcoast Transmission Co. Ltd.	3,329	1+18	3,329	1+18
Totals	8,888		6,295	
Current surplus without exports	6,440		6,440	
Current surplus (deficit) with new exports	(2,448)		145	
Including license granted to ICG Transmission in August, 1970	(2,652)		(59)	

Source: National Energy Board, Report to the Governor in Council: August, 1970, p. 10-71.

Mines and Resources in September of 1970. The Minister's provision that "price arrangements should be reviewed at future dates in the event that there is significant change in circumstances",[12] is noteworthy.

It is, however, the effects on the field producers and exploration companies which are of interest in this thesis and, therefore, only these effects will be pursued here.

The liberalization of contractable reserve calculations, the small deficit of 59 Bcf. created (see Table 9), the rejection of the Consolidated Natural Gas application (resulting in subsequent re-application to the Board), the reduced terms applicable to the licenses, and the low export prices approved[13] must all be considered conducive to increased exploration and development within the province.[14] The present demands for gas and the competition that potentially exists (from Consolidated Natural Gas) can only serve to increase field prices. Had export prices been set higher, the stimulus would have been much greater.

The late 1950's witnessed a very rapid increase in the demand for gas owing to the installation of the Westcoast and Trans-Canada transmission systems. Again in the late 1960's and early 1970's, demand is pressing severely on supply. The "directionality thesis" that was advocated in Chapters I and II would therefore suggest a marked increase in exploration and development for gas during these periods. This has in fact happened, as Table 10 indicates and later discussion of the 1969 decision of the Oil and Gas Conservation Board will

TABLE 10

PERCENTAGE OF SUCCESSFUL EXPLORATION AND DEVELOPMENT WELLS CLASSIFIED AS GAS-PRODUCING, 1956 to 1970

Year	Gas Wells as a Percentage of Successful Wells		Total Wells Drilled	
	Exploration	Development	Exploration	Development
1970	78.7	62.7	987	853
1969	49.1	48.3	1,036	841
1968	45.5	39.7	975	829
1967	40.9	26.2	756	820
1966	54.5	20.1	824	792
1965	46.9	11.9	891	1,083
1964	49.4	13.6	709	1,122
1963	46.1	14.6	652	1,046
1962	64.3	21.5	504	1,053
1961	57.8	20.5	551	1,052
1960	63.3	12.2	561	1,131
1959	57.2	14.4	549	1,031
1958	59.2	9.4	519	1,031
1957	40.0[a]	n/a	n/a	n/a
1956	40.0[a]	n/a	n/a	n/a

Sources: Oil and Gas Conservation Board of Alberta, Summary of Monthly Statistics, 1970 (Calgary: 1971), p. 452.

Canadian Petroleum Association, Statistical Yearbook, annual issues from 1958 to 1969.

R. A. Simpson, D. M. Nowlan and D. W. Rutledge, The Natural Gas Industry in Canada, 1960 (Ottawa: Mineral Resources Division, Department of Mines and Technical Surveys, 1962), p. 11.

[a]These percentages are for Western Canada as a whole. All other figures in the Table are for Alberta only.

elaborate. The percentages shown for 1970 are particularly dramatic and this is significant.

Setting of "Exportable Surplus" by the Oil and Gas Conservation Board[15]

Section 8, subsection (3) of The Gas Resources Preservation Act, 1956 states that:

> The Board shall not grant a permit for the removal of any gas or propane from the Province unless in its opinion it is in the public interest to do so having regard to
>
> (a) the present and future needs of persons within the Province, and
>
> (b) the established reserves and the trends in growth and discovery of reserves of gas or propane in the Province.

In assessing whether or not an exportable surplus exists, the Board categorizes reserves and requirements into "contractable" and "remaining". "Contractable" reserves are those reserves which are currently available for delivery (or soon will be) and which are either under contract for delivery or which are ready for delivery contracts. "Contractable requirements" are an offset to contractable reserves in that they represent total commitments of contractable reserves to Alberta utility companies and industries and to existing permit-holders. By comparing the contractable reserves and commitments of those reserves, the Board determines whether or not an exportable contractable surplus exists.

"Remaining" reserves (or "future" reserves) include a judgment portion (about 75 per cent) of proven reserves currently deemed to be beyond economic reach (under existing

technological and economic conditions). Remaining reserves also include proven reserves whose production is deferred during the next one to three years for conservation reasons[16] but which can reasonably be expected - within thirty years - to be produced. A third - and most important - component of remaining reserves is the Board's estimate of gas reserves which are not yet discovered or developed but which the Board expects will be found and developed fairly soon. Against these future reserves is calculated "remaining requirements" which consists of Alberta needs for 30 years plus a "cushion" to protect peak day requirements in the thirtieth year.

If the calculations indicate that a contractable surplus exists, then (provided the application is satisfactory in all other respects and a future surplus exists) the Board will issue a permit to the applicant to remove gas from the province. If a contractable surplus exists but there is a future deficit, then the Board must decide to what extent it is willing to increase its reliance on the future growth of reserves. Otherwise, part of the contractable surplus will be used to offset the future deficit until the situation changes. Hence, the contractable surplus sets the limit which can be exported and any existing future deficit acts as a constraint on these exports.

Table 11 provides an illustrative calculation of the Board's method of computing contractable and future surpluses. Before presenting the changes brought about by the Board's October, 1969 decision - and at the risk of perhaps belabouring

TABLE 11

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS AS ESTIMATED BY THE OIL AND GAS CONSERVATION BOARD - ILLUSTRATIVE ONLY
(All volumes in Tcf. at 1,000 BTU/cubic foot)

Entry Number	Item		Amount
	Contractable Reserves:		
1.	Now considered within economic reach		42.0
2.	Less: Deferred for conservation reasons		6.0
3.	Total contractable reserves		36.0
	Contractable Requirements:		
4.	Contractable Alberta requirements		8.0
	Permit requirements -		
5.	To meet commitments	25.0	
6.	To meet terminal year peak day	2.0	27.0
7.	Total contractable requirements		35.0
8.	Contractable Surplus		1.0
	Remaining (Future) Reserves:		
9.	From deferred gas available within 30 years		5.0
10.	From reserves now considered beyond economic reach		2.0
11.	From reserves providing for terminal year peak day in permits		0.1
12.	From gas not yet established		12.0
13.	Total remaining reserves		19.1
	Remaining (Future) Requirements:		
14.	Total Alberta requirements for delivery		15.0
15.	Less: Deliveries from contractable reserves		6.0
16.	Deliveries required from future sources		9.0
17.	Total Alberta requirements for 30th year peak day		5.0
18.	Less: Available from contractable reserves		2.0
19.	Required from future sources to meet peak day requirements		3.0
20.	Total remaining requirements		12.0
21.	Remaining (Future) Surplus		7.1

--continued--

TABLE 11 (continued)

Source: Oil and Gas Conservation Board of Alberta, Report and Decision On Review of Policies and Procedures for Considering Application Under The Gas Resources Preservation Act, 1956: October, 1969 (Calgary: 1969), p. 73. (Format altered somewhat.)

TABLE 12

RESULTS OF THE 1969 REVIEW BY THE OIL AND GAS CONSERVATION BOARD OF POLICIES AND PROCEDURES USED IN CALCULATING EXPORTABLE SURPLUS

Item Number (from Table 11)	Board Policy Prior to 1969	Changes Proposed By The Canadian Petroleum Association	Decision
19	A growth rate set at the lesser of the long-term (post-1950) growth rate or that of the immediately preceding 24-month period.	Annual growth rate to be based on experience of the immediately preceding 10 years.	Suggestion accepted by the Board with the provision that the Board may modify the growth rate based on factors such as a decreased rate in the latter years of the 10 year period, the general state of the economy or "pertinent political or regulatory developments in the marketing region", (among others).
19	Two years growth of gas reserves allowed in calculating gas surplus for the period.	Number of years growth of reserves to be tied to potential and already discovered reserves by the formula: Years of growth allowed $= \frac{\text{Potential reserves - Ultimate Reserves}}{10}$ where potential reserves are total ultimate recoverable	Accepted by the Board with the proviso that potential reserves be conservatively estimated. The number of years will be rounded to the nearest half-year (which in our example is 5.0 years).

--continued--

TABLE 12 (continued)

		marketable reserves discovered in Alberta at the date of calculation. If (for example) we assume potential reserves to be 100 Tcf. and 51 Tcf. as currently ultimately recoverable, then: Number of years growth $= \frac{100-51}{10} = 4.9$	
2,9	Deferred reserves not included in calculating contractable surplus.	Deferred reserves that can reasonably be expected to begin producing during the first 10 years of the 30-year protection period be included as contractable reserves.	Reserves which are presently deferred but which will commence initial production within 3 years are to be included plus those deferred reserves to be produced in the near future and which are under firm contract to an exporting company and are included in a permit (or application for permit) to remove gas. The portion classified as being contractable will depend upon approved or projected producing rates.

Source: See Reference to Table 11 (deleting page number).

the obvious - it should be emphasized that a company holding a contract for gas purchases which finds itself unable to export gas from Alberta because of an existing future deficit is going to incur a cost and the producers in the field will likewise suffer.[17] Changes in the calculation methods that will serve to increase estimates of future reserves or estimates of contractable surplus are, therefore, desirable to the industry and expansionary to it. Table 12 summarizes the methods used by the Board prior to 1969, the changes proposed by the Canadian Petroleum Association (Alberta Division) and the decision made by the Board.[19]

The Effect of the October, 1969 Decision of the Oil and Gas Conservation Board

The foregoing discussion clearly indicates that gas exploration and development activity in the Province of Alberta was justifiably expanded in 1970 - as shown in Table 10. Development of the Strachan-Ricinus area has been quite intensive since its discovery and it is abundantly clear that the problem facing the gas industry during the 1970's will not be one of finding markets but, rather, reserves - about two and one-half times the reserves proven up during the 1960's.[20]

A potential danger for investment in the province is the possibility of reserves falling to less than 30 years requirements. If future reserves fell from 30 years requirements for Alberta to (let us say) 25 years requirements, exploration and development might be choked off (since the incentive to prove up reserves would be lacking owing to the inability of

producers to sell to export firms). Much would depend on the reason for the drop in future reserves. If it were the result of a temporary slowdown in the economy then the adverse effects on exploration might not materialize. If, on the other hand, the decrease in reserves were due to a permanent slowdown in the finding rate, then a decline in exploration and development would be very probable as the amount of reserves "on the shelf" (or what one could term "excess capacity") adjusted to the then existing sales levels.

Other Regulatory Activities of the Oil and Gas Conservation Board[21]

The legal rule of capture allows producers to keep whatever oil or gas they bring to the surface regardless of whether it has migrated from neighbouring properties. In the early days of the industry much oil was wasted as producers drilled wells in a dense pattern along the edges of their properties in an effort to drain oil and gas from neighbouring properties. Many reservoirs were ruined from the resulting loss of natural drives and flooding of reservoirs by water. The glut of oil created by such practices resulted in prices being driven to ruinously low levels. The result was government-enforced conservation controls which are now an accepted fact in the oil and gas industry. Unfortunately the pure conservation aspect of enhancing ultimate recoveries has become somewhat confused with price-stabilization, especially in the case of oil.

There are two main ways to view conservation.[22]

The first is that of the "wise" use of the nation's limited supply of natural resources and is a problem of dynamic general equilibrium in that the use of the resource (and substitution for the resource) should be co-ordinated with long-run economic growth and change. The second economic meaning of conservation can be termed a theory of ideal output. Stated differently, it is an attempt to optimize the time-rate of use of the resource. Resources possess both "stock" and "flow" characteristics. For commodities such as oil and gas a conservation decision must be made as to the rate of use of the currently existing stock and another decision (dependent on the first, of course) as to the amount of investment in renewing the current stock as it is depleted (that is, exploration and development). As McKie and McDonald put it: "The optimum rate of depletion of known stocks is mixed with the economics of an investment cycle".[23]

For both oil and gas there is a maximum rate of production or withdrawal from the reservoir that can be achieved without causing water flooding and loss of otherwise produceable reserves. The concept of the Maximum Efficient Rate (M.E.R.) has thus evolved to account for this engineering problem in reservoir management. M.E.R. is tied to economic efficiency in that - for oil particularly - it is the maximum production consistent with maximization of net revenues. Reducing the production rates for oil will enhance ultimate recovery but may be too costly in terms of postponing revenue generation.[24] For gas there is little to be gained in terms of ultimate re-

covery by reducing the production rate (assuming a given number of wells and a given well spacing pattern). Therefore, the maximum daily (and annual) production is set by characteristics of the reservoir itself and varies greatly within the province. The Oil and Gas Conservation Board establishes maximum daily and annual withdrawals for gas wells but for most pools the production rate is set by the sales contract. The daily maximum depends on the pressure differential in the well zone.

The result is that over time the productivity of a well will decline at a fairly predictable rate - denoted as ab in the diagram below. Sales contracts for a pool or a field will usually specify maximum (and minimum) takes (with some allowance for eventual decline of production in the field). In the diagram below, cd is the maximum take specified in a sales contract.

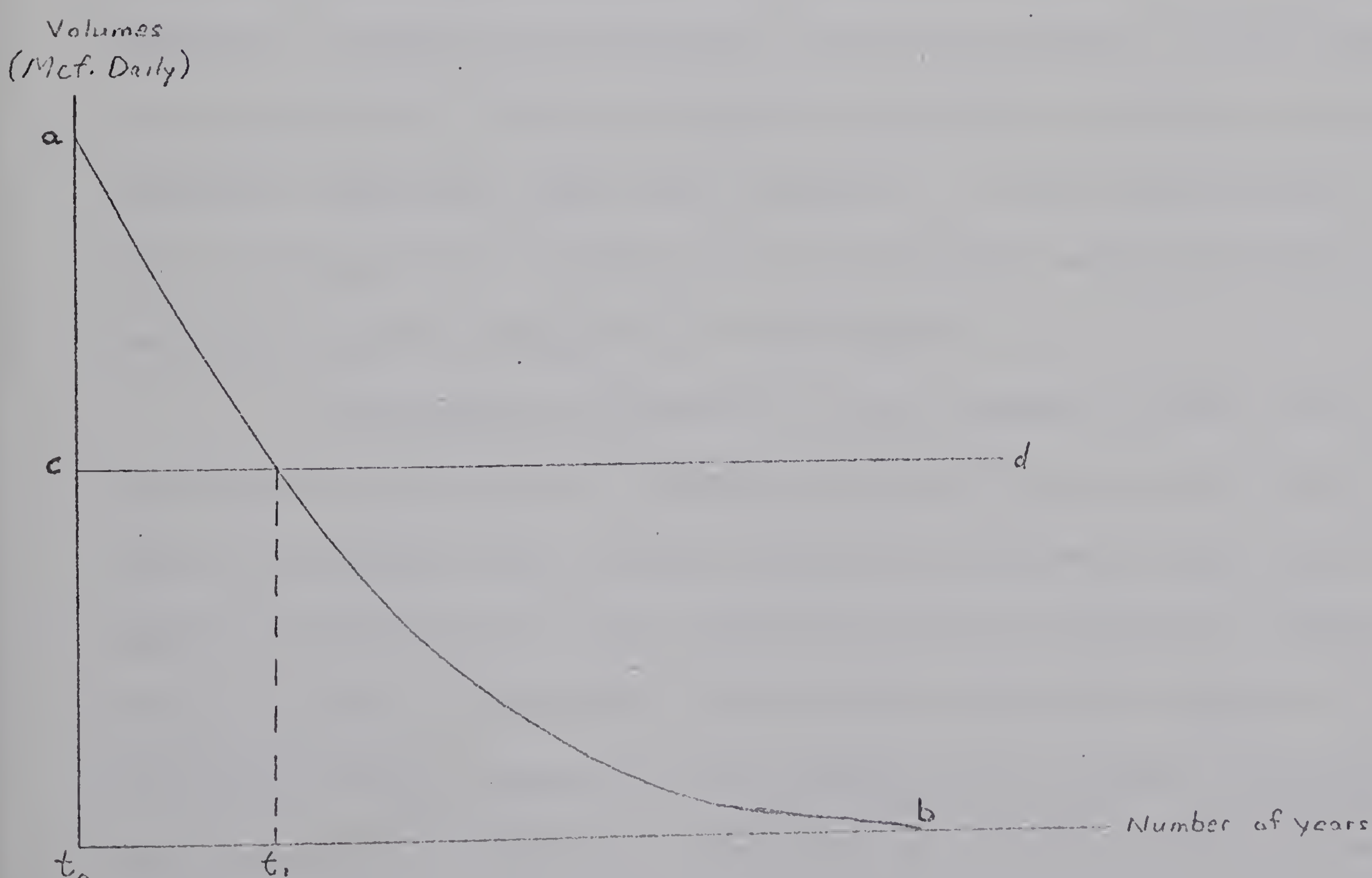

Fig. 3 Productivity of an individual well and maximum take in the field per existing well

All of the foregoing ignores well spacing and assumes a given number of wells in a pool. The drilling of new wells at time t_1 will enable producers of the field to continue meeting the maximum take provisions and therefore represents another investment decision point. Well spacing (for gas wells only) is set largely by convention - at one per 640 acres. When productivity of the field as a whole begins to decline to very low volumes, it may become necessary (in an economic sense) to space wells closer than one per section. When this occurs (and the early stage of development of Alberta's fields has made it a rare occurrence), the producers will go to the Board for permission to drill wells closer together. These regulations have not changed over the past 15 or more years.

Generally speaking, then, wells drilled in a reservoir are spread far apart and infill drilling occurs over time as economic circumstances warrant and productivity of the older wells declines. While it might be possible to drain an entire reservoir with one well (for example, in the Medicine Hat field) this is clearly not optimal in an economic sense and has not been the typical pattern of development.

Unitization of pools is very common in gas but is not required by the Board - largely because there is no harm to other producers from taking maximum withdrawals from each well (and no benefits to a well operator by not doing so) and if the daily maximum is exceeded the operator runs the danger of ruining his well and his share of the reserves that would otherwise have been recovered. There are interference effects between wells

(even with 1 well per section) but these effects are not significant for ultimate recovery. Two wells drilled one mile apart will, for all intents and purposes, double capacity. Naturally the closer together the wells are placed the greater the interference and the smaller the increase in capacity.

The results of the foregoing discussion can be summarized as follows:

(1) ultimate recovery in a reservoir is essentially constant (provided maximum production rates per well are not exceeded);

(2) each well in a reservoir will be operated at the maximum output consistent with this given ultimate recovery;

(3) the greater the number of wells, the greater will be the annual production in the reservoir (until the reservoir is depleted) and the higher the gross discounted revenues that will be received (assuming prices constant over time);

(4) the slope of the cumulative gross discounted revenue curves for a reservoir decline over time both because of the discount factor and the diminishing output per well caused by declining pressures in the reservoir.

These results are referred to and utilized further in Chapter IV where patterns of development in fields are examined.

Land Acquisition

The Province of Alberta owns about 85 per cent of the petroleum and natural gas acreage which is leased by firms in

the industry.[25] The system of reservations and leases currently in effect[26] was mentioned briefly in Chapter II and only those aspects which affect industry investment patterns need be mentioned here.

The purpose of the present system of selling oil and gas rights is to encourage exploration and allow the Province of Alberta to share in successful exploration programs. The government sells drilling reservations, natural gas licenses, drilling permits in "Block A"[27] and ordinary petroleum and natural gas reservations on the condition that a certain amount of exploratory work be done and with a sliding scale of rentals that escalates during the time that a reservation is in force. These reservations must be converted to leases if commercial quantities are located and may be converted at the option of a reservation holder at any time. However, not all the acreage covered by a reservation may be leased. At least 50 per cent reverts to the Alberta government. The reservation holder takes up to 50 per cent of the acreage in what might be called a "checkerboard" pattern. That is, leases are for plots of land no larger than 4 miles long by 2 miles wide or 3 miles in length and 3 miles in width. The leased plots may not touch each other except at the corners. The province will then auction the acreage that has reverted to it and this proven or semi-proven acreage will sometimes fetch very high prices.

The result of this system of selling acreage is to generate fairly rapid proving up of fields. If reservation holders were permitted to take 100 per cent of the acreage in

lease form there would not be the stimulus to develop a field as quickly. The present system causes other companies to rush in to any new prospective area and the regulations require fairly early drilling in these areas. The result is more rapid development of provincial reserves than would otherwise occur. Any new major discovery is, therefore, likely to be followed by increased exploration in the area and higher bonuses paid for drilling reservations.

FOOTNOTES

[1]The discussion in this section is based on Richard E. Hamilton, "Canadian Natural Gas Export Policy", a paper presented at the meeting of the Canadian Economics Association, June 1-10, 1971.

[2]The 20 years growth in initial reserves was to be calculated as 20 times the average absolute increase over the preceding 10 years. The reader may wish to make his own conclusions as to the adequacy of this method in adjusting to the long-run discovery rate for gas.

[3]These criteria were established in the Board's 1967 Westcoast decision. National Energy Board, Report to the Governor in Council: August, 1970, p. 5-31.

[4]Ibid, p. 5-19.

[5]Ibid, p. 8-21.

[6]Ibid, 5-34 and 5-35. Since Alberta and Southern does not make any significant sales in Canada, the Board did not feel it could meaningfully apply the second test. The quotation in the text diminishes the importance of the second test although the Board also felt "that prices to Canadian customers in the same area [Kingsgate is about 30 miles East of Vancouver] compare favourably with the export price". [5-33]. It is interesting to note that the price to be charged by Alberta and Southern at Kingsgate, B.C. was to range from a low of 24.1 cents per Mcf. in 1969 to 30.0 cents per Mcf. in 1986 "after which the price would increase rapidly". [5-22].

Reference to the Dominion Bureau of Statistics publication, Gas Utilities, 1967 (Ottawa: Queen's Printer, 1971), p. 11 indicates that the average British Columbia prices in 1967 (primarily in the Vancouver area) were as follows:

Type of Customer	Volume (MMcf.)	Price per Mcf.
Residential	20.4	$1.47
Industrial	42.7	0.42
Commercial	12.0	1.17
Total	75.1	0.82

The most appropriate comparison is with the industrial price and, presumably, part of the industrial price charged represents profit and/or recovery of a portion of fixed costs of the utility.

[7]National Energy Board, <u>op.cit.</u>, p. 5-35.

[8]<u>Ibid</u>, p. 10-26.

[9]<u>Ibid</u>, p. 10-28.

[10]<u>Ibid</u>, p. 10-30.

[11]Apart from the general shortage of gas and the reluctance to approve export projects by companies not selling to Canadians over those of companies who do sell domestically, there is the problem encountered in the case of Alberta and Southern which the Board naturally wished to avoid in the future. It stated:

> The discussion of the Alberta and Southern application illustrated the difficulty of finding that the price to be charged for gas to be exported is just and reasonable in the case of a cost of service project which is reaching optimum operating levels, particularly when it does so in a period of fairly general and rapid increase in energy prices. The finding required by the Act has not been readily reached in respect of the current application by Alberta and Southern, and the Board would be reluctant to approve the commencement of another like project in which the same or greater difficulties are already discernible.
>
> . . . .
>
> Once a large diameter pipe line is in place, the "cheap expansibility" available in it gives its owners a very powerful lever in seeking supply contracts and authorizations to develop the system to optimum capacity, but the cost of service concept makes it unlikely that Canada would receive the full value of gas exported in the later stages of development of such a system.
>
> . . . .
>
> The system would almost inevitably result in decreasing border prices in a period when such gas as may become surplus to Canadian requirements will be increasingly valuable.

National Energy Board, <u>op.cit.</u>, pp. 10-41 to 10-43.

Consolidated Natural Gas Limited has reapplied to the National Energy Board (to be heard July 13, 1971). Essentially the arrangement is that Trans-Canada Pipe Lines Ltd. would transport Consolidated's gas reserves - in its facilities - to the United States where Consolidated would buy back half the gas (in the early years at least). The objection of the National Energy Board to another export trunk line is thereby removed.

Industry reaction to the rejection of the Consolidated application was interesting. <u>Oilweek</u> (October 5, 1970) pointed

out that the logic of the National Energy Board decision was to virtually prohibit exports by any company other than Trans-Canada Pipe Lines Ltd. (east of Alberta) since Trans-Canada sells domestically as well as to the United States. At that time Consolidated had paid $53 million in prepayments for gas and was planning an additional $35 million in 1971 in take-or-pay commitments (which it fully intended to fulfill). Oilweek, October 5, 1970, pp. 5, 8.

At the time of writing (July 5, 1971), Consolidated has invested close to $90 million in Alberta but is no longer purchasing gas in the province. Competitive bidding for gas has, therefore, ceased at this point although prices for new reserves do not appear to have fallen, as yet.

[12] Hamilton, op.cit., p. 6.

[13] It should be noted that prices in Canada are regulated and are, therefore, presumably at least not higher than would exist in the absence of regulation. Hence the 105 per cent proviso that was adopted for the Trans-Canada Pipe Line exports may still be "low" relative to the price that domestic consumers would be willing to pay.

[14] At a later point, the differences between development-inducing vis à vis exploration-inducing changes will be considered. For the time being this point will be ignored and the effects simply considered expansionary to both types of reserves creation.

[15] The policies of the Board are presented in each of its Reports on the various applications made to it to export gas from the Province of Alberta. However, the best source - and the one most used in writing this section - is the Report and Decision on Review of Policies and Procedures for Considering Applications Under the Gas Resources Preservation Act, 1956: October, 1969 (Calgary: 1969).

[16] Reserves of gas are frequently deferred for reasons of oil conservation (e.g., associated gas in a pool) or where the gas has considerable propane (or heavier hydrocarbon) content and is being cycled to prevent the loss of liquids.

[17] The Canadian Petroleum Association estimated the cost (before taxes) to the gas producing industry of carrying an unsold developed inventory of one trillion cubic feet of gas at $3.3 million per year. While insufficient details of the method used to determine this cost prevent evaluation, it doesn't seem unreasonable or high (based on present wellhead prices for gas) and it does serve to illustrate the point. Oil and Gas Conservation Board, op.cit., p. 7.

[18]Decreasing the estimates of future needs would accomplish the same purpose, of course, but would be tactically unwise for any party to suggest and is therefore not considered as a possibility.

It should be made clear at this point that the matter-of-fact method of presenting these details does not imply a negative judgment by the author as to the desirability of gas exports. Rather, the beneficial effects which these exports have had on the economy of the province should be emphasized. This does not deny the need however to maximize the short-run and long-term effects of this resource to Alberta and to Canada as a whole.

[19]Other decisions reached included changes proposed by the Board itself. Although regular reserves hearings were decided against, there will be regular hearings (initially every 3 years) to assess future provincial requirements. Interim adjustments to future requirements will be made by formula in order to save time at each hearing dealing with export permits. The adjustments to be made by formula will apply to both total 30-year requirements and the 30th year peak-day requirements. It is not important to consider these formulae in detail here.

[20]This has been repeatedly emphasized in various issues of Oilweek during the past two years. If these reserves are forthcoming - both in Alberta and from offshore drilling in Eastern Canada - then, Oilweek predicts a 315 per cent increase in sales between 1970 and 1980 and a one-third increase in the average field price to producers (no adjustment indicated for inflation). Oilweek (January 19, 1970), pp. 35-40.

[21]Much of the information presented in this section results from an interview on June 30, 1971 with Mr. G. J. DeSorcy, Manager of the Gas Department of the Oil and Gas Conservation Board in Calgary. I am grateful to Mr. DeSorcy for his assistance and patient responses to questions. Any errors in this section are, of course, the responsibility of the author.

[22]James W. McKie and Stephen L. McDonald, "Petroleum Conservation in Theory and Practice", Quarterly Journal of Economics 76 (1962), pp. 99-101.

[23]Ibid, 101.

[24]This refers primarily to oil and depends upon the type of natural drive present. Gas-cap and water drives decrease in effectiveness as production rates are increased. Solution gas drive allows production to occur within a fairly wide range without affecting ultimate recoveries. Non-associated

gas reservoirs (and associated gas remaining in pools after the oil has been produced) are largely immune to this inverse relationship of production rates and total ultimate recovery. There is, though, a definite maximum production rate for gas wells which, if exceeded, will cause water-flooding.

[25]Canadian Petroleum Association, Statistical Yearbook, 1969 (Calgary: 1970), p. 6.

[26]See Hanson, op.cit., Chapter 16 and Conder, op.cit. for a complete description of land acquisitions in the province. A discussion with Mr. H. H. Sommerville, Deputy Minister of the Alberta Department of Mines and Minerals, on July 29, 1971 indicated that very few changes (all minor) had occurred since the extensive revision of the Mines and Minerals Act in 1962.

[27]"Block A" was established in 1962 as "that part of the Province in townships one to sixty-four inclusive between the fourth and fifth meridians." That part of the province was considered unlikely to yield any extensive oil field in the future (since it had been fairly intensively explored) and, therefore, this area was granted more generous terms for acquiring Crown rights. Conder, op.cit., 36.

CHAPTER IV

DEVELOPMENT OF NATURAL GAS FIELDS IN ALBERTA

An Unconstrained Model of Field Development

In Chapter III the interrelationships between production rates, ultimate recovery and well spacing were discussed and the policies of the Oil and Gas Conservation Board presented. For natural gas, ultimate recovery in a field is essentially constant (provided maximum production rates per well are not exceeded) and each well is operated at maximum output consistent with this given ultimate recovery. Annual production in the reservoir will, as a result, be higher for greater numbers of wells until interference effects nullify the gains from the installation of additional wells. Higher levels of annual production result in the receipt of higher gross discounted revenues (assuming prices constant over time) but the slope of the cumulative gross discounted revenue curves for a reservoir will decline over time as pressures in the reservoir decline and the discount factor increases in importance.

In Figure 4 below,[1] 3 possible cumulative discounted gross revenue curves are shown (DGR_1, DGR_2 and DGR_3). Each of these curves corresponds to a given number of wells - all being operated at maximum output consistent with fixed ultimate recovery. Denser well spacing results in higher discounted gross revenues being received but also in interference between the wells which results in the distance between discounted gross revenues increasing at a declining rate as the number of wells

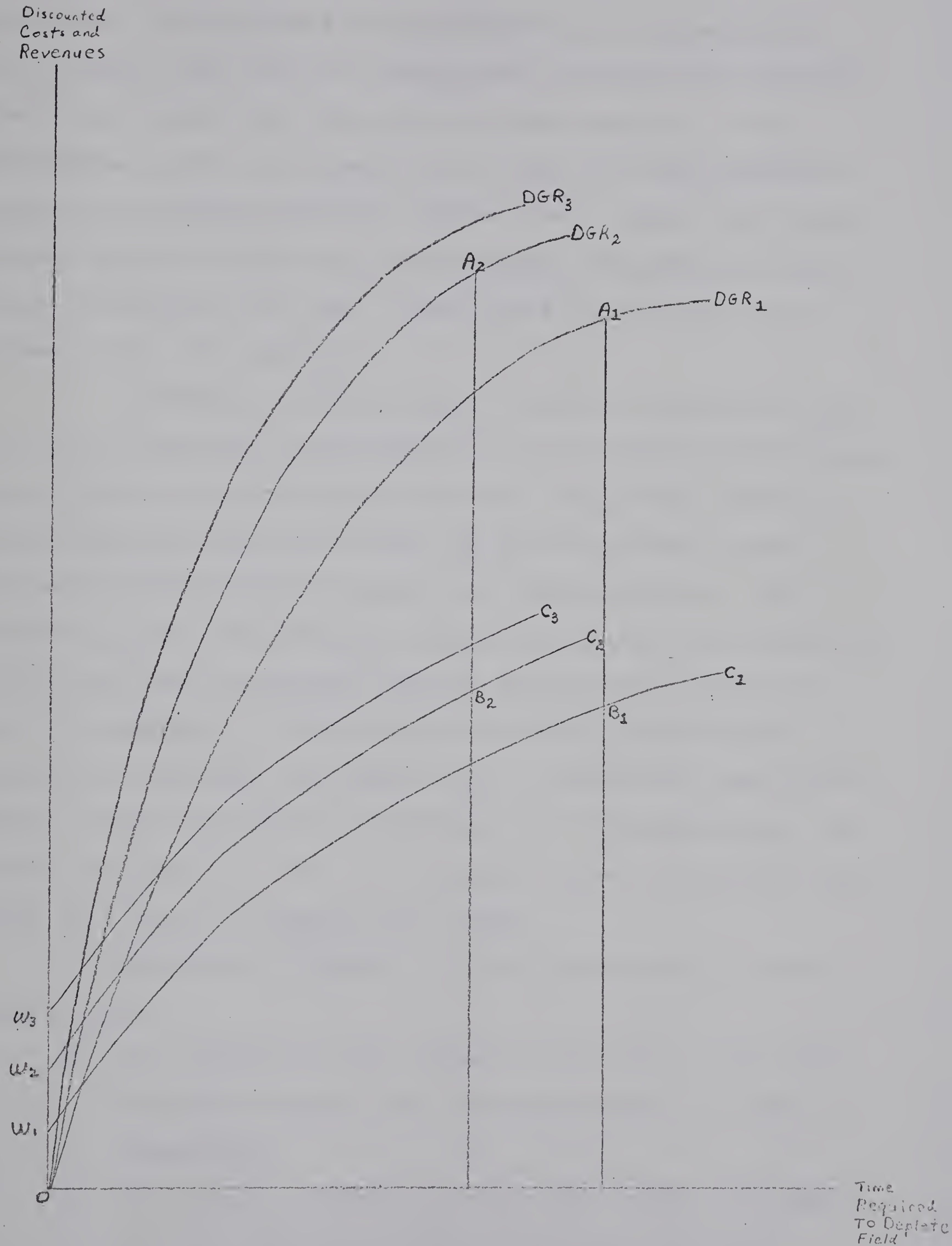

Fig. 4 Model of field development

increases. For purposes of predictability and presentation, it is useful (at first) to assume that all wells are installed before any production takes place in the reservoir. Then, discounted gross cost curves (C_1, C_2 and C_3), which represent denser well spacing patterns, can be shown. These cost curves have a positive slope owing to the impact of production costs which accumulate over time. Fixed costs for the wells are shown as OW_1, OW_2 and OW_3.

In Figure 4 the AB segment reaches a maximum of A_2B_2. Up to W_2, additional wells add more to gross discounted revenues than they do to gross discounted costs. Beyond W_2 additional wells interfere with each other and do not increase annual capacity sufficiently to justify the additional cost. The amount A_2B_2 is the difference between development and production costs and gross discounted revenues (which we may assume are net of royalties). Finding costs and lease payments above the annual fee (bonuses) are fixed prior to production (sunk costs). Hence, these costs must be recovered from the amount A_2B_2. If rents and discovery costs (on average[2]) exceed the portion A_2B_2, then exit from the industry will occur.

Reference to Figure 4 allows the following (static) predictions:

(1) if production costs increase (the slope of the cost curves increases) then later production will not be undertaken;

(2) an increase in drilling costs will reduce the number of wells drilled in future reservoirs (present

reservoirs would be unaffected) but a decrease in drilling costs would create more intensive development of existing reservoirs;

(3) a rise in exploration costs and land bonuses will reduce exploration efforts;

(4) an anticipation of future price increases will prolong the rise of the DGR curves and shift production in existing pools toward the future. Exploration would increase.

In Chapter I (footnote 19 and surrounding discussion in the text), the MacAvoy explanation of well completions in a field was presented. His description implies that all wells (and field equipment) are installed prior to initial deliveries. However, this would only be true provided a ready market was available for all the gas in the field and contract constraints such as those described by Figure 3 in Chapter III were not present. As it is, in Alberta, there will exist a pattern of well development in each field which is a function of the contract signed.

Actual Patterns of Development in Gas-Only Fields of Alberta

Table 13 provides an indication of the pattern of well development in the "gas-only" fields of Alberta by showing the number of "capable" wells at the end of each year in each of the fields. It should be noted that "capable" wells, as defined, exclude capped gas wells. Also, not all capable wells are necessarily in operation at any particular time. The data

TABLE 13

CAPABLE WELL COUNT IN SELECTED MAJOR GAS FIELDS OF ALBERTA

Name of Field	Year of Discovery	Initial Marketable Gas as of December 31, 1969 (Bcf.)	1952	1953	1954	1955	1956	1957	1958	1959	1960
Beaverhill Lake -	)		-	-	-	-	-	-	-	n/a	n/a
Fort Saskatchewan	1946)	523	-	1	10	13	15	18	20	22	25
Berland River	1958	341	-	-	-	-	-	-	-	-	-
Bigstone	1959	321	-	-	-	-	-	-	-	-	-
Bindloss	1952	351	-	-	-	-	n/a	9	11		
Burnt Timber	1959	250	-	-	-	-	-	-	-	-	-
Gold Creek	1964	388	-	-	-	-	-	-	-	-	-
Jumping Pound (and West)	1944	1520	-	-	-	-	-	-	2	2[a]	2[a]
Lookout Butte	1959	450	-	-	-	-	-	-	-	-	-
Marten Hills	1964	892	-	-	-	-	-	-	-	-	-
Medicine Hat	1904	2014	67	75	84	82	82	82	119	162	184
Okotoks	1951	170	-	-	-	-	-	-	-	n/a	n/a
Pendant D'Oreille	1946	249	8	12	12	12	12	15	19	19	19
Pine Creek	1956	346	-	-	-	-	-	-	-	-	-
Pine North-West	1963	176	-	-	-	-	-	-	-	-	-
Pouce Coupe	1922	114	4	4	4	4	3	11	12	13	13
Pouce Coupe South	1953	107	-	-	-	-	1	11	12	17	19
Quirk Creek	1967	500	-	-	-	-	-	-	-	-	-
Strachan	1967	1200	-	-	-	-	-	-	-	-	-
Viking Kinsella	1914	845	104	104	104	105	108	111	114	117	117
Waterton	1957	2137	-	-	-	-	-	-	-	-	-
Westlock	1949	259	-	-	-	-	n/a	5	5	5[a]	5[a]
Wildcat Hills	1958	700	-	-	-	-	-	-	-	n/a	n/a

--continued--

TABLE 13 (continued)

Name of Field	Year of Discovery	Initial Marketable Gas as of December 31, 1969 (Bcf.)	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970
Beaverhill Lake -	)		2	2	2	2	8	13	13	13	13	18
Fort Saskatchewan	1946)	523	27	30	31	31	31	31	31	31	31	32
Berland River	1958	341	-	-	-	-	-	-	-	-	-	-
Bigstone	1959	321	-	-	-	-	-	-	-	3	3	3
Bindloss	1952	351	11	11	17	21	21	21	23	21	29	29
Burnt Timber	1959	250	-	-	-	-	-	-	-	-	2	2
Gold Creek	1964	388	-	-	-	-	-	-	-	-	-	10
Jumping Pound (and West)	1944	1520	2	2	12	12	12	12	12	18	21	25
Lookout Butte	1959	450	-	-	3	4	4	4	5	7	8	9
Marten Hills	1964	892	-	-	-	-	-	-	-	-	21	24
Medicine Hat	1904	2014	205	232	319	361	397	419	445	482	501	563
Okotoks	1951	170	5	5	7	8	8	8	9	9	9	10
Pendant D'Oreille	1946	249	20	22	24	25	27	30	33	34	40	43
Pine Creek	1956	346	-	8	8	9	13	16	16	16	16	16
Pine North-West	1963	176	-	-	-	-	-	-	3	3	4	4
Pouce Coupe	1922	114	13	13	11	11	11	11	11	11	11	11
Pouce Coupe South	1953	107	19	19	19	20	20	20	20	20	21	22
Quirk Creek	1967	500	-	-	-	-	-	-	-	-	-	1
Strachan	1967	1200	-	-	-	-	-	-	-	-	-	-
Viking Kinsella	1914	845	120	121	123	124	123	123	122	121	123	122
Waterton	1957	2137	-	12	14	15	16	18	18	18	19	21
Westlock	1949	259	5	5	10	15	16	17	18	18	20	20
Wildcat Hills	1958	700	2	6	7	8	9	9	12	13	15	15

Sources: Oil and Gas Conservation Board, Summary of Monthly Statistics, various issues; Cumulative Annual Statistics, various issues and Reserves of Crude Oil, Gas, ...: December 31, 1969, pp. II-6 to II-61.

[a] - assumed

n/a - not available

in Table 13 is utilized in Figure 5 to illustrate patterns in the development of fields. Considering the heterogeneity - both physically and economically - of the fields, there is a remarkably similar pattern of initial development followed by a plateau which is in turn followed by further development in the sixth to eight years of "active" development. "Active" development was deemed to occur when a field of less than five capable wells (usually zero to two) began to really develop. Frequently this period coincided with the commencement of operation of the Trans-Canada and Westcoast pipelines in 1957. Medicine Hat, Pendant D'Oreille and Viking Kinsella were not included in Figure 5 as they are older fields and data was unavailable for the early years.

Not only is the pattern of development interesting, it is also noteworthy that, in the majority of cases, at least one-half of the present (1970) capable wells in a field have been drilled within about four years (or less) of an available market coming into existence. Infill drilling has occurred as sales increase and reservoir pressures decline.

A Constrained Model of Field Development

It can be concluded (from the unconstrained model presented earlier) that field producers will prefer to drill the optimum number of wells early in the life of the field and produce at the M.E.R. until the field is depleted. Market and contract constraints will, however, bring about fairly constant production in the field which, with declines in pressure, will cause wells to be drilled throughout the entire life of the

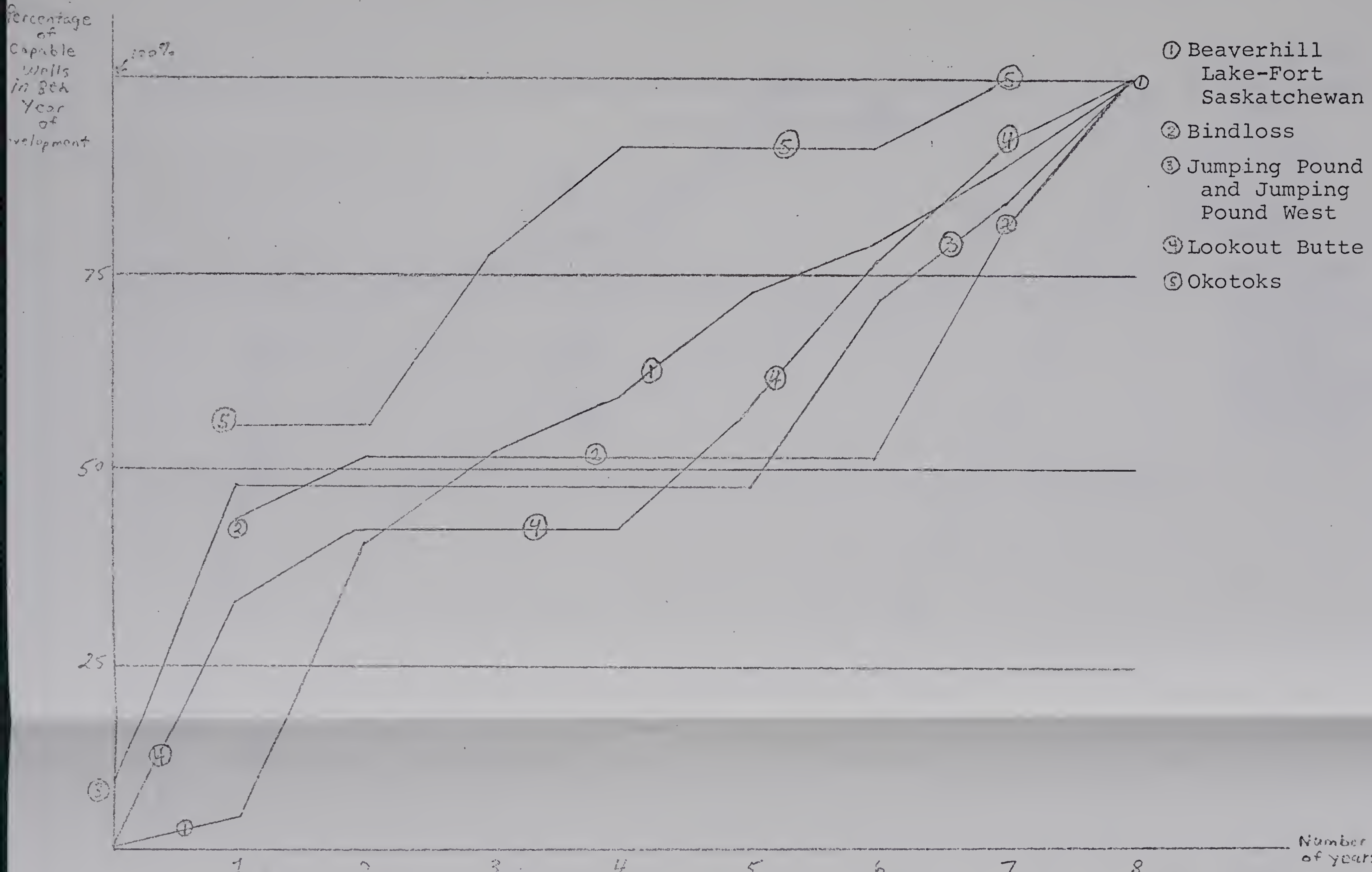

Fig. 5:1 Development of selected fields during first 8 years of active development in each field (in percentages of capable wells at the end of the 8 years)

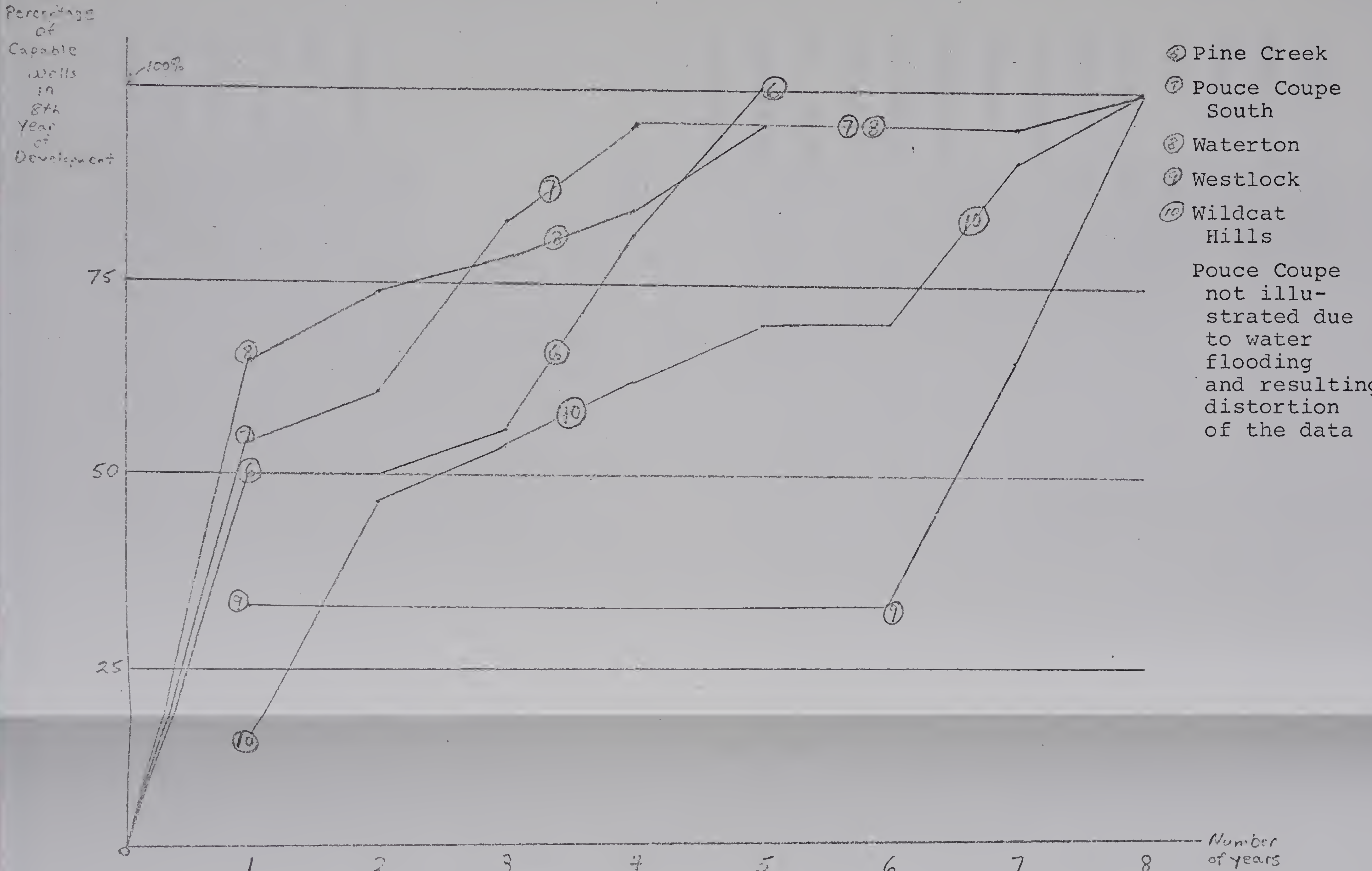

Fig. 5:2 Development of selected fields during first 8 years of active development in each field (in percentages of capable wells at the end of the 8 years)

field. The pattern in which these wells are drilled will depend on the contract provisions regarding the maximum "takes" from the field.

The case in which pipelines accept all gas produced in the field (an uncommon occurrence in Alberta) has already been covered implicitly in the discussion surrounding Figure 3 of Chapter III and in the unconstrained model presented in this chapter. Since production rates from a reservoir decrease proportionately with the amount of gas produced, the annual production will fall - exponentially[3] - over time if producers conform to the predictions of the unconstrained model and drill all the wells at (or near) the time of initial development and production. Mathematically, the production in any year t can be expressed as:

$$P(t) = be^{-ct} \tag{4.1}$$

where:

$P(t)$ = production in year t

b = production in year 1

c = rate of decline in the reservoir in percentage terms

The more common case of maximum annual takes from fields (with minimums for which the pipelines are obliged to pay[4]) results in producers achieving a fairly constant level of production each year equal to the maximum specified in the contract (seasonal variations and maximum daily quantity provisions ignored for the time being). Figure 6 below indicates greater numbers of wells (W_1, W_2 and W_3) corresponding to

different years. Essentially the producer attempts to have the maximum capacity from his wells coincide each year with the maximum annual production that he can sell (provided the variable costs of extraction are not greater than the price per Mcf.). Note that the installation of (say) W_2 wells in t_1 (rather than t_2) would have created excess capacity of MN and excess capacity is a cost to be avoided where possible.

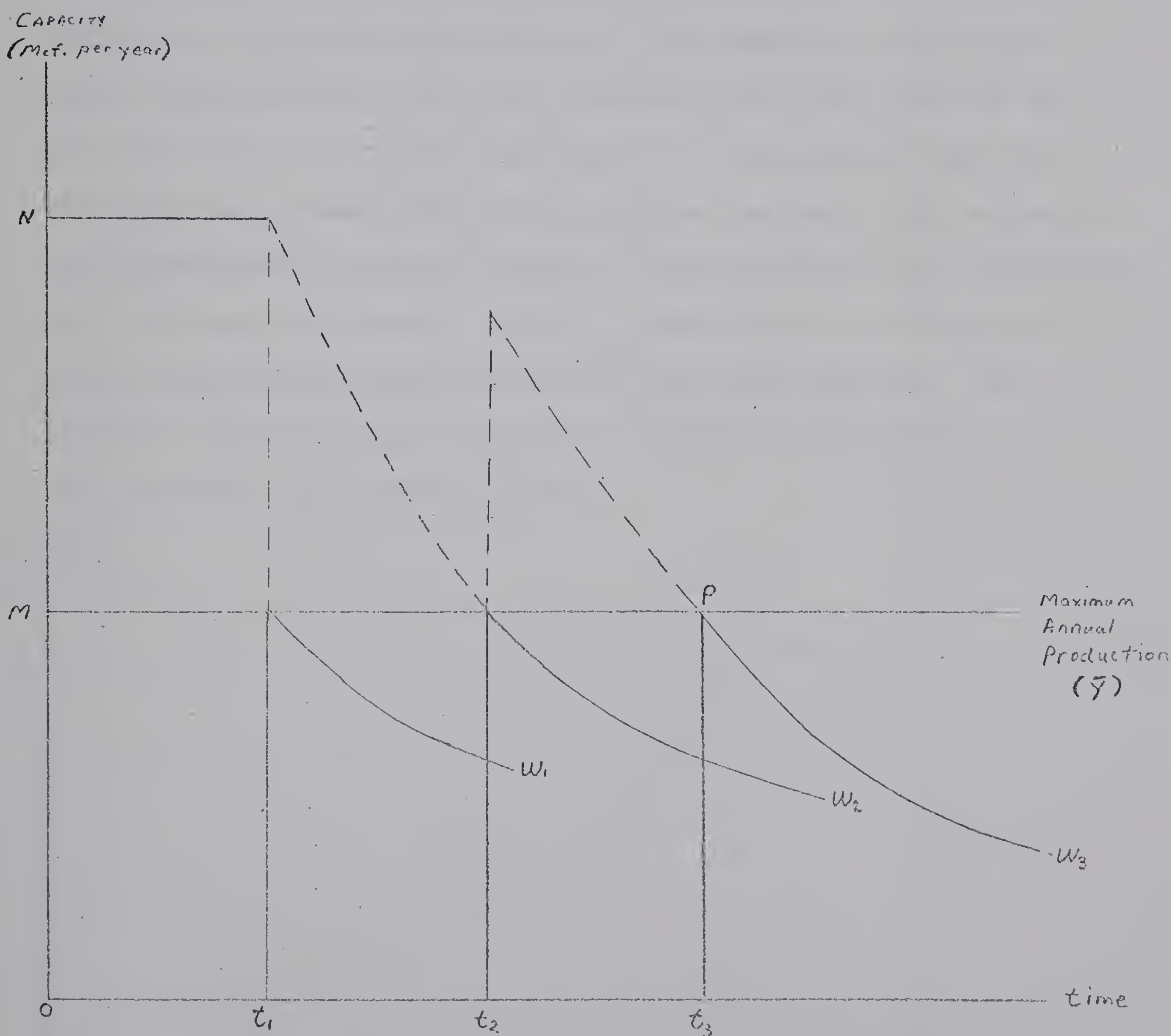

Fig. 6 Well installations with maximum annual production constraint

The assumptions involved in this model are that: (1) the price of wells relative to the overall price level does not change with time; (2) the well hole diameters (and, therefore, capacities) are the same for all wells in the field; (3) only complete wells are installed and add to capacity.

The producer will install a greater number of wells each year in order to maintain capacity as close to $\bar{y}$ as possible (with the maximum output constraint binding). Since reservoir production declines exponentially, the number of additional wells required each year will increase until the limit of one per 640 acres is reached although it is conceivable that development may cease before the limit is reached. The situation is illustrated in Figure 7 below. OM (reached at t_m) corresponds to 1 well per 640 acres. After t_m there will be no further wells drilled and capacity of the field will decline. The producer will no longer be able to maintain the constant level of production ($\bar{y}$) that he desires.

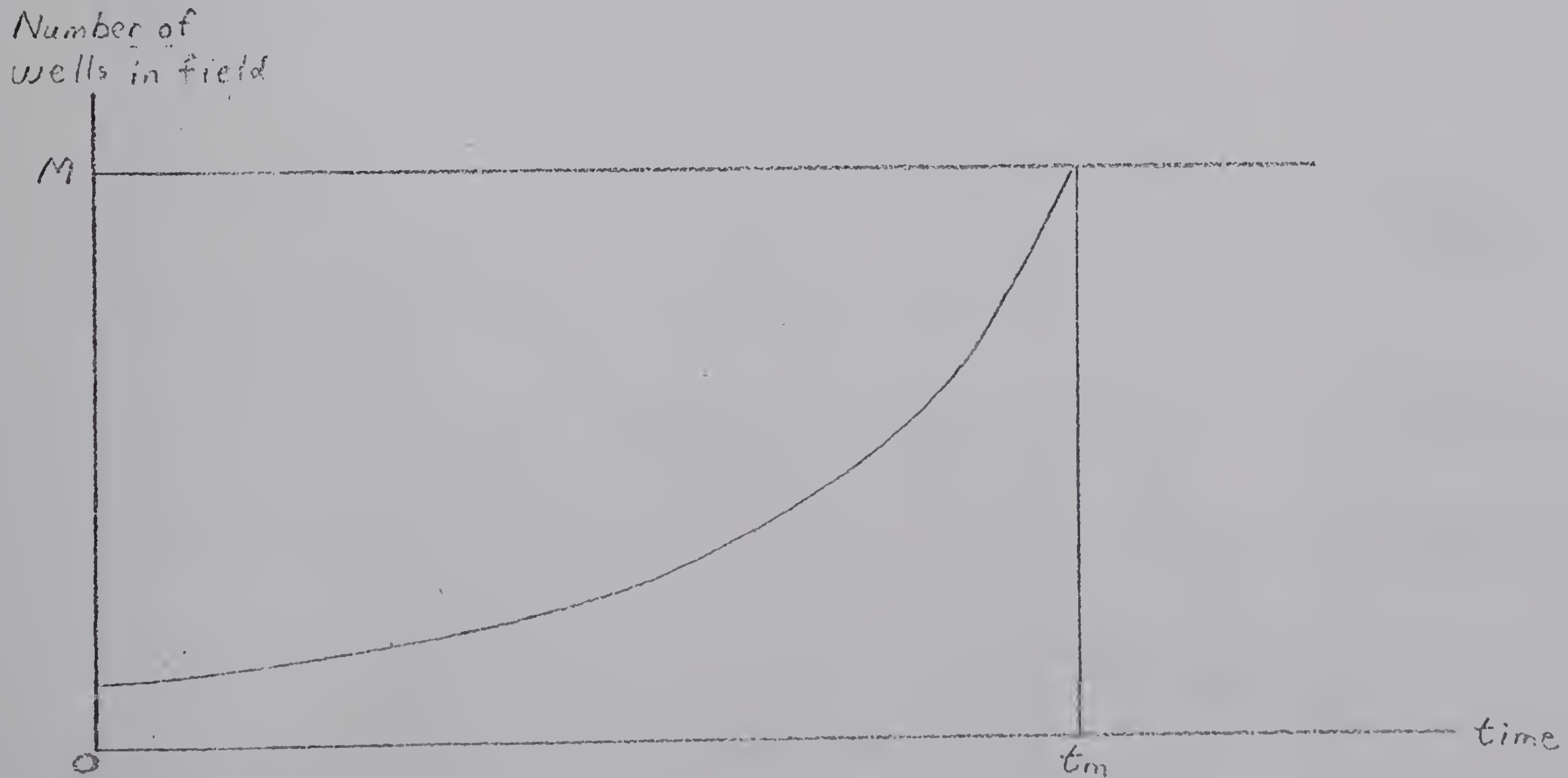

Fig. 7 Well installations over time to maintain constant annual output

The Constrained Model Extended

The foregoing has ignored seasonal fluctuations and maximum daily quantities in production. The modification required to the above analysis in order to incorporate these factors is not great. Figure 8 below is identical in concept to Figure 6 except that capacity is in terms of Mcf. per day and output fluctuates between OL and ON during the year. An interesting result of the production fluctuations is that investment in development wells must be higher to accommodate these production variations and the greater the seasonal fluctuation the higher the investment required. The desire of producers to reduce the investment in wells complements the desire of pipeline companies to maintain a constant throughput and creates stronger incentives for underground storage facilities and interruptible service arrangements with customers.[5] Well installations over time will again be observed.

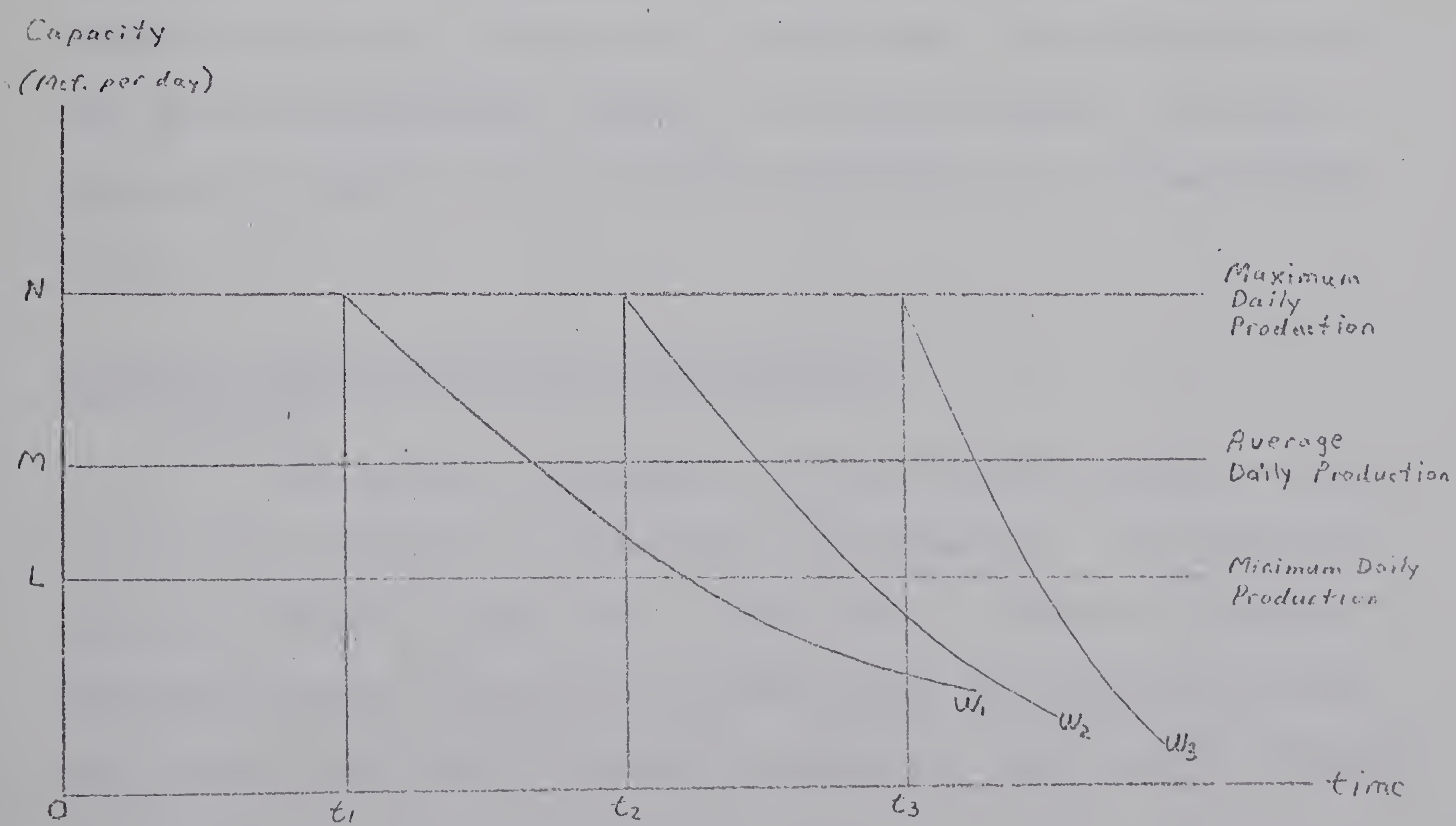

Fig. 8 Well installations with maximum annual production constraint and seasonal fluctuations

In summary, the constrained model of field development predicts (for maximum annual volumes) a continual increase in the number of capable wells over time. Table 13 and Figure 5 in fact indicate increases in the number of wells over time but also the occurrence of "plateaus" in the number of capable wells which last more than 3 years in 6 of the 11 fields analysed. Even when the Pouce Coupe field is eliminated (owing to premature water flooding[6]), one-half of the fields fail to conform to the model prediction in the strictest sense. Significantly, these five exceptions occur in the largest 7 fields. This may be the result of several producers in a unitized field putting wells in at the same time (thus creating temporary excess capacity). It may also reflect a desire by producers to build ahead of requirements in order to (perhaps) save money installing several wells at once or to gain time for the testing of wells and thus reduce the risk of being unable to deliver the gas at a later date. Without proving the above explanations though, it is not possible to claim empirical support for the constrained model in its strictest form.

Costs to Develop Natural Gas Fields of Alberta

The models developed in this chapter assume profit-maximizing behaviour on the part of producers. If good data existed for well capacities by year and if factors leading to observed excess capacity in fields could be better specified and quantified, then it would be possible (with given contract

conditions) to make fairly good estimates of the costs to develop individual fields in the Province. As these conditions were not present a different path was chosen in order to estimate development costs for certain fields in Alberta.

To estimate development costs per Mcf. of current production (or current production equivalent) for certain fields, the simplifying assumption is made that, from 1970 onwards, the field producers will act in a certain non-optimizing way. To be exact, it is first assumed that no further development wells are to be drilled and that production will be allowed to decline. In terms of Figure 6, this means that producers are assumed to be at P and no further wells are to be drilled. The validity of this assumption is tested later in this section.

Appendix I sets forth an estimate of the costs to develop the Medicine Hat gas field. Problems of estimating drilling costs are dealt with in that appendix. However, some of the major problems need to be re-emphasized here in order to caution the reader and guide his judgment as to the validity of the cost estimates derived in this chapter.

Using a model of well drilling costs that was derived from U.S. data, costs to drill a well were hypothesized to be of the form:

$$Y = K(e^{\alpha x^{o}} - 1) \qquad (4.5)$$

where:

Y = well costs, exclusive of overhead

X = well depth in feet

K = a parameter representing the cost of

a well of depth X^o (approximately 3,500 feet) such that $(e^{\alpha x^o}-1) = 1$

α = a parameter ranging around $2X10^{-4}$ for the U.S. data analysed.[7]

Using average footage and well cost data from the Canadian Petroleum Association's Statistical Yearbook (and adjusting the data for the exponential relationship hypothesized) a value for K of $49,000 (in terms of 1962 dollars) was derived. The value of α was assumed to be $2X10^{-4}$ (as for wells drilled in the U.S.) and was further assumed to be constant over time. Naturally, these are strong assumptions to be making.

This model of well drilling costs can be used to estimate costs for various fields in the Province using average well depths published by the Oil and Gas Conservation Board.[8] The resulting costs are in terms of 1962 dollars and are then converted to a 1969 base year by use of the general wholesale price index.

Two problems now arise. The first involves the cost of capital for the industry. Since costs (and production) are to be expressed in terms of 1969 as a base year, the cost of capital for the industry must be used to both gross up pre-1969 costs (and production) and discount post-1969 costs (and production). The second problem relates to forecasting the decline rate (in percentage terms) applicable to natural gas fields. Both of these problems are crucial to the final cost figures derived and must be handled explicitly.

Cost of capital in the industry has been widely

estimated between 8 and 16 per cent with the most probable range being between 10 and 15 per cent. In recent years, with interest rates generally rising, a value close to 15 per cent seems quite reasonable and appropriate.[9] In the calculations of costs (for the fields chosen) both 10 and 15 per cent figures were used. A more precise estimate of the cost of capital for the industry in Alberta was beyond the scope of this analysis.

Earlier in this chapter the decline over time of reservoir pressures and reservoir production (for any given number of wells) was referred to. Cumulative production from a reservoir (with any given level of investment) can be expressed mathematically as:

$$\int_{o}^{T} P(t_o)e^{-(c+r)t}dt \tag{4.6}$$

where:

$P(t_o)$ = initial output

c = the rate of decline of output as the reservoir is developed

r = the discount rate[10]

In the absence of better information, decline rates of both 2 and 5 per cent were postulated for the fields selected.

Four fields were selected for analysis. All had been developed recently (during the 1960's) and all were in the western part of Alberta where well depths range between about 9,000 and 12,000 feet. Hence the well drilling costs were quite high. These well drilling costs were calculated in terms of 1969 dollars and grossed up to 1969 costs using a 10 and a 15 per cent discount rate. Actual production to 1970 was expressed

in terms of 1969 production using both the 10 per cent and the 15 per cent discount rate. Production from 1970 to 2,000 A.D. (in all cases production to 2,000 A.D. was physically possible) was estimated according to equation (4.1) where b was taken as being 1970 production and the decline rate (c) was arbitrarily assigned values of 2 and 5 per cent. Production past the year 2,000 was ignored.

Results of the analysis are contained in Table 14.

TABLE 14

ESTIMATED DEVELOPMENT COSTS FOR SELECTED FIELDS IN ALBERTA

Field	Costs in cents per Mcf.		
	r = 15% c = 5%	r = 10% c = 5%	r = 10% c = 2%
Jumping Pound West	3.034	2.179	1.837
Lookout Butte	4.388	3.094	2.752
Waterton	3.455	2.205	1.980
Wildcat Hills	2.806	2.128	1.922

Sources: Calculated using procedures outlined in Appendix I and discounting production using production data from the Oil and Gas Conservation Board, Summary of Monthly Statistics, various issues. Information on reserves and surface losses from the Oil and Gas Conservation Board, Reserves of Crude Oil, Gas, ...; December 31, 1969, Part II.

The estimates range from less than 2 cents per Mcf. (at a discount rate of 10 per cent and a decline rate of 2 per cent) for Jumping Pound West to about 4½ cents per Mcf. for Lookout Butte (at a discount rate of 15 per cent and a decline rate of 5 per cent). Based on these assumptions, an average development

drilling cost per Mcf. for reasonably new fields would seem to be in the 2½ to 3½ cents per Mcf. range.

Development drilling expenditures (for both gas and oil) in the period 1967 to 1969 comprised about 30 per cent of the total expenditures of the industry in Alberta for development drilling, field equipment, "other" capital expenditures and capital expenditures for natural gas plants.[11] Wells in the fields chosen average about $462,000 in terms of 1969 dollars while development gas wells in the Province as a whole from 1967 to 1969 averaged only about $90,000 each. "Average" costs per Mcf. would be about .5 to .7 cents per Mcf. and, using this figure, we can estimate development expenditures in an average field as being about 2.1/3 times the "average" drilling costs per Mcf. - about 1.2 to 1.6 cents per Mcf.

The total development costs for the four fields chosen would then be in a range from about 3.3/4 to 5.1/4 cents per Mcf.[12] Because the four fields that were chosen have very deep producing zones, their well drilling costs (and, therefore, the costs per Mcf.) are higher than for other fields and the 3.3/4 to 5.1/4 cents estimate will, therefore, approximate the marginal cost of developing new fields in Alberta.

Underlying all of the analysis in this section has been the assumption that producers will drill no more wells in future. However, if the marginal development plus extraction cost is less than the price received, then there is an incentive to develop the field more quickly even though the average development cost per Mcf. will rise. To determine the sensi-

tivity of the estimates derived, the Waterton field was selected for further analysis. Cost estimates were derived assuming that 1970 production was maintained by drilling of more wells (as required) until 5 additional wells had been drilled. As there were 22 wells in the field at the end of 1970, this was considered a fair increase in capacity. It was further assumed that interference effects between the wells did not exist although this is questionable since the field will only take 24 wells at the regular well spacing requirement of one well per 640 acres.[13]

The result of this analysis was, that at a decline rate of 2 per cent, 1 well was added every second year from 1971 to 1979 while, at a decline rate of 5 per cent, 2 wells were added in 1971 and 1 well each year from 1972 to 1974. For a discount rate of 10 per cent and a decline rate of 2 per cent, costs per Mcf. increased by less than a tenth of a cent (to 2.051 cents per Mcf.). For a discount rate of 15 per cent and a decline rate of 5 per cent, costs per Mcf. increased to 3.541 cents per Mcf. - about one tenth of a cent higher than the estimate given in Table 14. The marginal cost of the twenty-seventh well was 2.856 cents for a discount rate of 10 per cent and a decline rate of 2 per cent and was 3.589 cents with a discount rate of 15 per cent and a decline rate of 5 per cent. Were the field larger there would be an incentive to drill even more development wells (given the existing price for gas) and average development costs would rise to a somewhat higher amount.

FOOTNOTES

[1]McKie and McDonald, op.cit. develop a more difficult model for oil where well spacing and production rates affect ultimate recovery as well as the timing of revenues. The model presented herein is a simplification and adaptation of their approach.

[2]The term "on average" reflects the fact that imperfect knowledge of a reservoir exists prior to production and development. Firms can only make educated guesses and, when wrong, fail to recover part of the sunk costs.

[3]Bradley, op.cit. uses exponential production declines for oil reservoirs with generalized gas-drive. The exponential decline is a good approximation for natural gas reservoirs and is used throughout this chapter.

[4]The Financial Post Corporation Service, "Trans-Canada Pipe Lines Limited", (Toronto: McLean-Hunter Limited, recent basic card).

[5]In 1970, 45.5 per cent of the gas produced during the year was produced in the six-month period from April to September. However, the difference between the highest month (December) and the lowest month (June) was 67.5 Bcf. or a 43.8 per cent increase from June to December. Oil and Gas Conservation Board, Summary of Monthly Statistics, 1970, op.cit., p. 321.

[6]Discussion with Mr. V. Jones, Senior Technician in Edmonton branch of the Oil and Gas Conservation Board on June 7, 1971.

[7]F. M. Fisher, Supply and Costs in the U.S. Petroleum Industry - Two Econometric Studies, Part II: "Measuring the Effects of Depth and Technological Change on Drilling Costs", (Baltimore: Resources for the Future, Inc. - The John Hopkins Press, 1964).

[8]Oil and Gas Conservation Board, Reserves of Crude Oil, Gas, ..., 1969 (Calgary: 1970).

[9]Charles A. Norman, "Economic Analysis of Prudhoe Bay Oil Field", in M. A. Adelman, Paul G. Bradley, and Charles A. Norman, Alaskan Oil: Costs and Supply (New York: Praeger Publishers, 1971), pp. 40-41.

[10] Based on Bradley, op.cit., pp. 22-23.

[11] Canadian Petroleum Association, Statistical Yearbook, 1969, op.cit., p. 125.

[12] Using expenditures data from the Canadian Petroleum Association's, Statistical Yearbook, this estimate can be placed in perspective. Royalties range from about 2½ to 3 cents per Mcf. (before allowable deductions). Exploration expenditures for both oil and gas for the period 1967 to 1969 were almost one and one-half times total development costs thus yielding a very rough estimate of about 5 to 8 cents per Mcf. for exploration (for the industry as a whole). Processing plant operating costs range from 3.1/3 to 4 cents per Mcf. (with larger volumes yielding costs in the lower end of the range). Lifting costs appear to range from about 1.1/4 to 1.3/4 cents per Mcf. These costs when added to the development cost derived yield a wide range for natural gas costs of 16.1/3 to 22 cents per Mcf. with a middle value of about 19 cents. This estimate accords reasonably well with the field price that existed for new gas reserves in 1969 but ignores necessary profits for the industry.

[13] Oil and Gas Conservation Board, Reserves of Crude Oil, Gas, ..., 1969, op.cit., p. II-58.

CONCLUSION

This thesis has sought to establish the proposition that natural gas is both economically separate and analytically separable from oil and other energy sources. Natural gas (both associated and non-associated), oil and natural gas liquids occur in fairly distinct geological patterns. Furthermore, about 70 per cent of the gas reserves of Alberta are non-associated with oil. Hence, there is ample opportunity to explore for gas separately from oil and to assign exploration costs accordingly. Although surprises will occur from time to time in exploration, it is possible to attach probabilities to various formations and possible to determine whether firms are involved in either oil or gas search. Decisions by firms to abandon wells will also be based on these probabilities and prior experiences in the area.

Further research collecting data from the drilling applications filed with the Alberta Oil and Gas Conservation Board or the drilling reservation applications filed with the Alberta Department of Mines and Minerals seems warranted. It would enable exploration costs in the industry to be split (using published expenditures data) and would overcome one of the major problems in deriving an investment function for gas within the Province. Collection of a price series reflecting current prices paid for new reserves would overcome the second major problem in deriving an investment function and is, therefore, also warranted.

An investment function for gas exploration and

development would be a first step in attempting to quantify the impact of regulation by various local, provincial and federal government agencies on Alberta's economy. Approximately 75 per cent of the gas production in the Province is destined for export and this factor creates a significant impact on the Alberta economy. The recent liberalization of requirements for export of gas from Alberta and from Canada were discussed in Chapter III. Such changes were shown to have a considerable impact on gas exploration and development activity in 1970 and serve to highlight the need for analysis of the impact of regulation on Alberta by various government bodies. The danger of possible adverse impacts on Alberta's economy if reserves should fall to less than 30 years' requirements was also pointed out in Chapter III.

The processing, transmission and marketing stages of the industry in Canada are quite highly concentrated (owing largely to available economies of scale). The oligopsonistic power over numerous field producers and the fact that large quantities of gas are available at low (short-run) marginal costs mitigate against the earning of economic profits at the production stage and act to keep field prices of gas low. Such effects also have implications for economic activity in Alberta that deserve more intensive examination.

Not only can exploration costs be separated and assigned to gas or oil, the theory of joint supply and joint cost was used in Chapter II to show that marginal costs for gas (or oil) can always be defined for development and pro-

duction - even in the fixed proportions case of solution gas. Also in Chapter II the difference between economic cost and replacement cost was discussed. The use of a modified replacement which lagged finding and development costs according to some average time between expenditures and production might work reasonably well in future analysis - especially if costs are discounted over time.

Chapter IV presented models of development of gas fields. It was shown that, if producers were unconstrained by markets and pipeline company contracts, they would drill all wells at (or near) the time of initial production and produce at M.E.R. until the field was depleted. Contract constraints will generate fairly constant production levels and a continuing program of development drilling in fields. The statement of the development problem in diagrammatic form should provide a basis for a more intensive field by field analysis of costs. Such analysis could be of assistance in planning reservoir development. It would also be of benefit in further analysing underlying supply conditions in the natural gas industry of Alberta.

The final section of Chapter IV was devoted to estimates of development costs in certain selected fields of the Province using a method which discounted both costs and production. While the estimates are somewhat crude they do indicate a reasonably low development cost for gas. This serves to explain the rapid expansion of the industry in 1970 after the liberalization of export permit requirements by the Oil

and Gas Conservation Board and the National Energy Board.

Further research into underlying supply and cost conditions in the industry seems well justified and would, of course, be vital in formulating an investment function for the natural gas industry in Alberta.

GLOSSARY

Allowable: The regulated rate of production of oil or gas, as set by regulatory boards.

Associated Natural Gas: Free natural gas in immediate contact, but not in solution with crude oil in the reservoir.

BCF (Bcf): A billion cubic feet (see Cubic Foot).

Bottom Hole (Rock) Pressure: The closed-in pressure at the bottom of a gas well.

British Thermal Unit (BTU, Btu or B.T.U.): The amount of heat required to raise the temperature of one pound of water one Fahrenheit degree.

Carbon Black: A finely divided carbon produced by the incomplete combustion of natural gas.

Casing: Lengths of steel pipe threaded together and cemented in a well to support the walls of the well and prevent them from caving in, or to shut off water zones in the well.

Casinghead Gas: Generally unprocessed natural gas which is produced from strata containing crude petroleum and/or condensate. Refers to both dissolved gas and associated gas. In the case of dissolved gas, the oil and gas is removed at the wellhead by mechanical separators.

Condensate: The liquid which separates from a gas due to a reduction in temperature and/or increase in pressure. The cooling of "wet" natural gas produces condensates.

Core: Cylindrical section of subsurface rock cut by a special tool in the process of drilling a well. Cores are cut through certain rock formations in order to examine the physical properties of the rock for indications of oil or gas.

Cracking: Processing that breaks down and rearranges the molecular structure of hydrocarbon chains. In thermal cracking, high temperature and high pressures are applied; in catalytic cracking, temperature and pressure are applied in the presence of a catalyst.

Crude Oil: Liquid crude petroleum as produced from subsurface geological structures before any processing or purification.

Cubic Foot, Standard: The volume of gas saturated with water vapour that at 60° F. and a pressure of 30 inches of mercury occupies one cubic foot. In the natural gas industry, generally, gas volumes are calculated on a dry basis at 60° F. and a specified base measure (e.g., 14.73 psia).

Dissolved Natural Gas: A gas resulting from the thermal decomposition of petroleum oils, composed mainly of volatile hydrocarbons and hydrogen. In its pure form, it has a heat content between approximately 1,300 and 1,500 BTU's per cubic foot.

Drill Bit: The heavy cutting tool that is used in drilling oil and gas wells. The cable tool bit is solid and has a relatively blunt cutting edge that is applied in repeated chopping strokes. The rotary bit is generally like an auger and grinds through rock; mud of special character is forced through perforations in the bit for cooling purposes and to carry cuttings to the surface.

Drilling: The mechanical operations of exploring for subsurface reservoirs of gas and oil for the purpose of production to the earth's surface.

Drill Stem Test: Test to determine the oil or gas productive capacity of a formation prior to completion of drilling of a well. Testing tool is attached to the bottom of the drill pipe and placed opposite the appropriate formation, allowing gas or fluids in the formation to flow up through the drill pipe.

Dry Natural Gas: Natural gas that does not contain crude petroleum or condensate, or gas from which the liquids have been removed.

Established Reserves: As used by the Oil and Gas Conservation Board of Alberta, these reserves are those whose existence can reasonably be counted upon. They include all of the proved reserves and a judgment portion (usually 50 per cent) of the probable reserves.

Ethane (C_2H_6): A hydrocarbon component of gas.

Exploration: The work that is involved in searching for subsurface reservoirs of gas and oil, preparatory to drilling for production purposes.

Extraction Plant: A plant for the separation of liquid hydrocarbons from a natural gas stream.

Field: The occurrence of several reservoirs in an area.

Flaring: The burning of gas from a gas well or from a gas-oil separator (see Casinghead Gas), for the purpose of safe disposal.

Fold: In geology, an uplifting and bending of rock strata due to earth movement, resulting in a wrinkle or fold in the strata. Such folds may serve as traps for gas and petroleum.

Formation: A geological term applied to an underground stratum; in the gas industry, usually the one from which gas or oil is produced.

Formation Pressure: The pressure of natural gas or oil as it is found under virgin conditions, in the underground formations from which it is produced.

Gas In Place, Initial: As used by the Oil and Gas Conservation Board of Alberta, this term refers to the volume of gas currently estimated to have been in the pool at discovery.

Gas-Oil Ratio: As produced from an oil well, the number of cubic feet of gas at atmospheric pressure divided by the number of barrels of oil or liquid will give the gas-oil ratio.

Gathering Lines: A pipe line system that has as its purpose the delivery of gas from a number of gas wells to either a processing plant or a central collection point in the field.

Hydrocarbon: A chemical compound composed solely of carbon and hydrogen. The compounds having a small number of carbon and hydrogen atoms in their molecule (e.g., methane) are usually gaseous; those with a larger number of atoms (e.g., propane) are liquid and the compounds with the largest number of atoms (e.g., paraffin waxes such as tricosane - $C_{23}H_{48}$) are solid.

Hydrogen Sulphide (H_2S): A compound of sulphur and hydrogen, gaseous in its natural state. It is found in manufactured gas made from coals or oils containing sulphur and is also found to some extent in some natural gas. It must be removed and has a noxious odour.

Inert: Not acted upon chemically by the surrounding environment. Nitrogen is an inert constituent of fuel gases; it dilutes the gas and does not burn itself; thus it lowers the heating value.

Initial Gas In Place: The volume of gas estimated by the Oil and Gas Conservation Board to have been in the pool at discovery.

Initial Marketable Gas: Calculated as the volume of gas initially in the pool (see Initial Gas In Place above) minus estimated reservoir loss and estimated surface losses (see Surface Loss below).

Lateral: A pipe, in a gas transmission or distribution system, that branches away from the central and primary part of the system.

Life Index: A measure of the number of years of gas reserves remaining based on current production.

Liquefied Petroleum Gases (LPG): A gas containing certain specific hydrocarbons which are gaseous under normal atmospheric conditions, but can be liquefied under moderate pressure at normal temperatures. Propane and butane are the principal examples. Propane has approximately 2,500 BTU's per cubic foot and butane approximately 3,175 BTU's per cubic foot. The value of LPG is that they can be stored as a liquid in tanks but converted to gas by people not served by gas utilities. LPG are also sold in bulk to utilities for peak-shaving and standby gas.

Looping: A paralleling of an existing pipe line by another line over the whole length or any part of it, to increase capacity.

Marketable Gas: See Initial Marketable Gas.

MCF (Mcf): One thousand cubic feet (see Cubic Foot).

MMCF (MMcf): A thousand, thousand cubic feet; i.e., a million cubic feet (see Cubic Foot).

Mercaptan: An organic chemical compound found in raw natural gas and frequently used to odorize natural gas and LPG for detection of leaks.

Methane: The first in the paraffin series of hydrocarbons (CH_4). It is colorless, odorless and inflammable and forms the major portion of natural gas.

Natural Gas: Combustible gaseous hydrocarbons occurring naturally in the earth's formations and formed in past geologic ages.

Natural Gas Liquids: Liquid hydrocarbon mixtures recovered by condensation and absorption from natural gas after it has been produced from the underground formations; includes natural gasoline, condensate and liquefied petroleum gases (LPG).

Natural Gasoline: Pentane and heavier hydrocarbon mixtures recovered or extracted from natural gas as it is produced from the underground formations.

Natural Gas Reserves: Volume of hydrocarbon gas existing in the natural formations of a specified area, which may be a field or pool. Proved recoverable gas reserve is the volume of gas that can be obtained from a particular area under specified physical conditions and with current operating procedures.

Nitrogen: An element (N) normally gaseous (N_2). It is odorless, colourless, and chemically will not support combustion and is generally inert. Nitrogen dilutes the BTU content of raw natural gas.

Non-Associated Natural Gas: Natural gas in a reservoir not containing oil, and therefore not in contact with, nor dissolved in, crude oil.

Pay Thickness: The bulk rock volume of the oil or gas-bearing reservoir divided by the area.

Permeability: Ability of a substance, such as rock or shale, to allow the passage of fluids through pores or voids.

Petroleum: A natural oil, composed primarily of hydrocarbons, existing in the earth's crust and produced by drilling wells into the deposits or extracting from oil bearing shales at or near the earth's surface.

Porosity: Usually expressed as a percentage, the voids in oil or gas-bearing rocks and shales.

Potential Reserves: An estimate of reserves considered to be available but not yet proven.

Probable Reserves: The reserves of gas estimated to be recoverable from the pool beyond the proved limits of the pool. The probable pool limits are based on normal geological expectation.

Propane: Gaseous member of the paraffin series of hydrocarbons (C_3H_8), that when liquefied under pressure, is one of the components of liquefied petroleum gas.

Proven or Established Reserves: Reserves of natural gas quantitatively defined by drilling. Usually the reserves are within the area of a pool completely delineated by drilled wells. A portion of proved reserves may be in drilling spacing units presently undrilled, but the nature of their occurrences is such that there is every reasonable probability that these reserves will be recovered.

Raw Natural Gas: Natural gas as it comes from the ground before it is processed or cleaned.

Reservoir: A structural arrangement of rock strata that forms a trap for the accumulation of oil and gas.

Rotary Bit: The cutting tool attached to the lower end of the drill pipe of a rotary drilling rig. The bit does the actual drilling of the hole through the formation.

Rotary Drilling: A method for drilling wells using a bit attached to a revolving drill pipe.

Royalty: The amount paid to the owner of land or mineral-rights for permission to produce the mineral content. In gas and oil operations, the royalty is usually based on a percentage of the total gas or oil production.

Solution Gas: See Dissolved Natural Gas.

Sour Natural Gas: Natural gas containing such amounts of sulphur compounds as to make it unusable without purifying.

Specific Gravity: As applied to gas, specific gravity is the ratio of the weight of a given volume to that of the same volume of air, both measured under the same conditions.

Sulphur: A chemical element (S), generally yellow in colour, that is an impurity in fuels, by itself or as sulphur compounds; with hydrogen and oxygen it forms corrosive sulphuric and sulphurous acids.

Surface Loss: The fraction of recoverable gas flared or used in removal of liquid hydrocarbons, acid gases, lease fuel and plant fuel.

Sweet Natural Gas: Natural gas containing such small amounts of sulphur compounds that it can be used without purification.

Well Depth, Average: The approximate depth of the mid-point of the pay zone for wells in the pool.

Wet Gas: A natural gas containing more than 0.1 gallons (U.S.) of condensate per Mcf.

Sources: Canadian Gas Association, Gas Dictionary (Don Mills, Ontario: 1963).

Earle Gray, Impact of Oil (Toronto: The Ryerson Press and Maclean-Hunter Limited, 1969), pp. 132-34.

Oil and Gas Conservation Board of Alberta, Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur Province of Alberta: December 31, 1969 (Calgary, Alberta: 1970).

APPENDIX I

A SAMPLE CALCULATION OF COSTS TO FIND AND DEVELOP THE MEDICINE HAT GAS FIELD

Exploration Costs

The Medicine Hat gas field is one of the oldest and largest fields in the province. The Alderson field, 40 miles northwest of Medicine Hat was discovered in 1883 in an effort by the Canadian Pacific Railway to find water. Similarly, the Medicine Hat field was located, seven year later, as a byproduct of search for another commodity - this time, coal. It was not until 1904 that the Medicine Hat field began to be exploited commercially.[1]

Since the field was inadvertently discovered in the search for another commodity, it is proper to ignore exploration in computing the costs for this field and proceed to the development stage.

Development Costs

As presented in Chapter 2, development costs include completion of exploration wells, the entire costs of all development wells (dry or productive), field equipment from the wellhead to the processing plant, the processing plant itself and the various leases required to maintain rights to the field between initial discovery and production. A special problem exists with leases in that a strong element of economic rent is involved and leases must therefore be treated rather carefully. Overhead may be added to these costs if desired.

The high methane content of the gas in the Medicine

Hat field (95.7%[2]) and the fact that it is entirely non-associated gas, result in there being no need for gas:oil separators or gas processing facilities. The high nitrogen content of the gas (3.8%) has induced the establishment of a fertilizer plant, details of which are not available.[3] Although the removal of nitrogen from the gas increases the BTU value of the gas, this processing step will be ignored in the cost calculations to follow. What field facilities exist must be largely ignored owing to the lack of information and, in part, the relative unimportance of these facilities.

Cost of Gas Wells

The total cost of gas wells in a field depends on: (1) the number of wells drilled (both dry and productive); (2) the year in which the wells were drilled; (3) the formations (and hardness of the rocks) through which the wells are drilled; (4) the location of the wells relative to established centres; (5) the actual cost of wells (for the relevant depths) drilled during the year in the field. It would be ideal if data were available for all of these items. For the sake of simplicity we can assume that drilling costs are kept to a reasonable amount by the proximity of the town of Medicine Hat thus ignoring factor (4) above. The effect of the rock formations in the field must also be ignored but we can assume that these formations keep drilling costs more moderate than they otherwise would be. With these simplifications in mind we can proceed to an analysis of the published data.

At December 31, 1964 there were 361 "capable" gas wells (of which 321 were operated) and 53 capped gas wells.[4] About 99% of these wells were in the Medicine Hat Sands formation. Early wells in the field were about 1,000 feet deep.[5] At the end of 1969 the average well depth had risen to 1,600 feet.[6] Fortunately, for purposes of this analysis, about 75 per cent of the capable gas wells in existence at December 31, 1964 had been drilled since 1957 as the Table below indicates. The major problems in the data presented are the lack of detail prior to 1964 and, more important, the exclusion of all dry wells drilled (or which may have been drilled) in the field. To determine the number of dry wells that have been drilled, it would be necessary to review the Summary of Wells published by the Oil and Gas Conservation Board of Alberta during the past few years. This was not done, partly because one suspects there have been very few dry wells drilled in the field and the resultant improvement in the final result would not justify the cost in time involved.

Once the number of wells drilled in the field have been determined, the next step is to attempt to relate the number of wells and their ages to the cost and, at this point, the analysis becomes subject to errors, the possible magnitude of which will be indicated from time to time.

The Canadian Petroleum Association (C.P.A.) has for many years published expenditure figures for the industry in their Statistical Yearbook. The wells drilled in Canada are classified by province, by type (exploratory or development)

TABLE 15

ANALYSIS OF GAS WELLS IN THE MEDICINE HAT FIELD, 1955 TO 1970

Year	Medicine Hat		Milk River A		Other Formations		Testing Wells	Total		
	Capable	Operating	Capable	Operating	Capable	Operating		Capable	Operating	Capped
1970	534	505	20	17	9	4	6	563	526	n/a
1969	492	479	-	-	9	5	4	501	484	n/a
1968	477	445	-	-	5	2	1	482	447	n/a
1967	440	416	-	-	5	1	-	445	417	n/a
1966	414	391	-	-	5	3	-	419	394	43
1965	392	366	-	-	5	3	-	397	369	43
1964	357	319	-	-	4	2	-	361	321	53
1963	n/a	n/a	n/a	n/a	n/a	n/a	n/a	319	n/a	n/a
1962								232		
1961								205		
1960								184		
1959								162		
1958								119		
1957								82		
1956								82		
1955								82		

Sources: Oil and Gas Conservation Board of Alberta, Summary of Monthly Statistics Alberta Oil and Gas Industry, various issues and Cumulative Annual Statistics Alberta Oil and Gas Industry, 1964, p. 123.

n/a - not available

and by type of exploratory well (new field wildcat, new pool wildcat, outpost, etc.). Each type of well is further classified as being a gas-producer, an oil-producer or dry. Until 1966 the exploration and development drilling expenditures were allocated to producers (oil or gas) and non-producers for total exploration wells and total development wells. It is thus possible to get average costs and average depths for oil-producing, gas-producing and dry wells by year. It must, however, be emphasized that the figures are only average and are for the province as a whole. The use of average figures presents many difficulties as noted a little later in this analysis.

Drilling costs per foot rise dramatically in deeper wells. The major reason for this increase is the need to replace bits more frequently at lower depths owing to the increased heat and harder rock formations. The replacement of bits is a long and tedious process that increases as the depth of the well increases.[7] Other costs (such as the derrick) are fixed while some of the variable costs (e.g., certain materials) change very little with increasing depth. F. M. Fisher, using U.S. data, was able to fit a basic well cost model which worked very well. The function he used was:

$$Y = K(e^{\alpha x} - 1)$$

where

Y = well costs, exclusive of overhead,

X = well depth, in feet,

K = a parameter representing the cost of a well

of depth X^o (approximately 3,500 feet) such that $(e^{\alpha x^o} -1) = 1$

α = a parameter ranging around $2X10^{-4}$ for the U.S. data analysed.[8]

Fisher explains α further as "the percentage change in marginal cost induced by a unit increase in depth" or "a measure of the curvature of the depth-cost relationship - the greater is α the greater the curvature".[9] K is derived as the ratio of a parameter H (the limit of marginal cost as depth approaches zero) to α[10]. It is expressed in dollar terms.

It must be noted that although α is given a constant value ($2X10^{-4}$), any drilling changes that change the cost of a deep well (relative to a shallower one) will affect the value of α. Lack of data necessitate ignoring the possibility that α changes over time or that its value is substantially different in Alberta than in the United States. These are, of course, strong assumptions to be making.

For a value of α of $2X10^{-4}$ and a given initial depth of (say) 5,000 feet, the exponential relationship indicates that total costs will double between 5,000 and 7,500 feet or between 10,000 and 13,100 feet. Marginal costs will double every 3,500 feet.[11] With an initial depth of 3,500 feet, total costs will double between 3,500 and 5,500 feet.

C.P.A. data has been used to calculate the average depth and cost of gas-producing development wells for the period 1958-1966. The average well depths for the period are 5,750 feet and average cost for these wells is \$111,120. However

these are arithmetic averages of costs and well depths and must, therefore, be adjusted to take account of the exponential relationship that has been hypothesized.

In order to arrive at values for K and an adjusted value for wells 5,750 feet deep (adjusted to take account of very high cost deep wells and relatively low cost shallow wells being averaged) assumptions must be made about the range of well depths included in the data. The simplest and most workable assumption is that the depths of the wells are normally distributed about the 5,750 foot mean. A second assumption must be made as to the range of well depths included in the data or - more precisely - within 2 standard deviations of the mean. Calculations were done for each 500 foot increment in well depths and the following assumptions made: (1) 60% of the wells drilled were between 5,000 and 6,500 feet; (2) a further 30% were included in the 4,000-4,500 and 7,000-7,500 foot categories; (3) the balance (10%) was assumed to be above 7,500 feet or below 4,000 feet. This results in a value for K of \$48,945 or, for the sake of simplicity, approximately \$49,000.[12] Substituting this value for K (and $\alpha = 2X10^{-4}$) in our basic well cost model yields an estimate of \$18,480 for a 1,600 foot well (1,600 feet being the average well depth in the Medicine Hat field). However, it should be remembered that this 1,600 foot figure is itself an arithmetic average of the well depths in the field. The estimate must, therefore, be increased to approximately \$18,600.

This figure must now be evaluated. Two major reasons

for suspecting the estimate to be low are as follows:

(1) the extreme shallowness of the wells, relative to the provincial average, raises the fixed cost per foot;

(2) the more recent wells in the field can be drilled (presumably) at lower costs per foot than the earlier wells. To estimate the early wells (1,000 feet) in terms of 1958 to 1966 costs and deflate by the wholesale price index would probably understate their cost.

Hence, an estimate of $25,000 per well seems justified using 1962 as a base year. This value is highly dependent on the assumed value for α and the hypothesized exponential relationship. The table below matches this estimated well cost with the wholesale price index to get a crude estimate of the costs involved to develop the Medicine Hat gas field (including overhead on wells drilled). Relative to the 2 trillion cubic feet of initial marketable gas in place in the field (as of December 31, 1969) the cost (in 1969 dollars) is remarkably low - less than 1 cent per Mcf.

TABLE 16

COST OF WELLS IN MEDICINE HAT FIELD

Year	Number of Wells Drilled[a]	Estimated Cost (1962 dollars)	General Wholesale Price Index[c]	Cost in 1969 dollars
1969	19	$ 475,000	282.4	$ 475,000
1968	37	925,000	269.9	967,839
1967	26	650,000	264.1	695,039
1966	22	550,000	259.5	598,535
1965	26[b]	650,000	250.4	733,067
1964	42	1,050,000	245.4	1,208,312
1963	87	2,175,000	244.6	2,511,120
1962	27	675,000	240.0	794,250
1961	21	525,000	233.3	617,750
1960	22	550,000	230.9	647,166
1959	43	1,075,000	230.6	1,264,917
1958	37	925,000	227.8	1,088,417
Prior to 1958	135	3,375,000	200.0[d]	3,971,250
Total	544	$13,600,000		$15,572,662
Add overhead costs - maximum of 10%[e]				1,557,266
				$17,129,928

Sources: Table 15 in this appendix and Dominion Bureau of Statistics, Prices and Price Indexes, various issues and Canadian Statistical Review, January, 1971 (Ottawa: Queen's Printer).

[a] Calculated as the change in capable gas wells from year to year adjusted for the capped wells (where known).

[b] 10 of the capable wells are assumed to have come from the reduction in capped wells during the year. All capped wells are assumed to have been drilled prior to 1958.

[c] 1935-39 = 100.0

[d] The index in 1949 was 198.3. In 1940 it was 108.0. The 200.0 figure has been deliberately estimated somewhat high to avoid understating costs.

[e] Reference to the C.P.A.'s Statistical Yearbooks indicates overhead of 10% of total development drilling to be a maximum in any year - frequently it is less than 10%.

FOOTNOTES

[1]Hanson, _op.cit._, pp. 40-41.

[2]_Ibid_, 237. [3]_Ibid_, 236-37.

[4]Oil and Gas Conservation Board of Alberta, _Summary of Monthly Statistics Alberta Oil and Gas Industry, 1964_ (Calgary: 1965), p. 167.

[5]Hanson, _op.cit._, p. 223.

[6]Oil and Gas Conservation Board of Alberta, _Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur Province of Alberta December 31, 1969_ (Calgary: 1970), pp. II-36 and II-37.

[7]F. M. Fisher, _Supply and Costs in the U.S. Petroleum Industry - Two Econometric Studies, Part II_: "Measuring the Effects of Depth and Technological Change on Drilling Costs", (Baltimore: Resources for the Future, Inc. - The John Hopkins Press, 1964), p. 44.

[8]_Ibid_, 44-50, 63-65. This study is summarized by Paul G. Bradley, _The Economics of Crude Petroleum Production_ (Amsterdam: North-Holland Publishing Company, 1967), pp. 64-66, 67-68.

[9]Fisher, _op.cit._, p. 48.

[10]_Ibid_, pp. 48, 50-51.

[11]_Ibid_, 65.

[12]It should be noted that the larger the standard deviation the lower is the value of K. In the extreme case of an equal number of wells in each class between 1,500 feet and 10,000 feet, K falls to $42,725. This value of K decreases the estimate for a 1,600 foot well to $16,110 - approximately a $2,500 decrease from the result in the method chosen. The other extreme value for K (if all wells were exactly 5,750 feet) is $51,395 and the resulting estimate for a 1,600 foot well is $19,380 - approximately $700 higher than in the method chosen.

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